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REGULATORY TREATMENT OF ELECTRIC UTILITY CLEAN AIR ACT COMPLIANCE STRATEGIES, COSTS, AND EMISSION ALLOWANCES

Kenneth Rose, Ph.D.
Senior Institute Economist

Alan S. Taylor
Senior Associate
RCG/Hagler Bailly, Inc.

Mohammad Harunuzzaman
Research Specialist

THE NATIONAL REGULATORY RESEARCH INSTITUTE
The Ohio State University
1080 Carmack Road
Columbus, Ohio 43210
(614) 292-9404

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EXECUTIVE SUMMARY

It has been recognized for over two decades that certain types of environmental pollutants should be controlled by governmental mandate. The reason is because the environmental costs of such pollutants to society are not "internalized" by the source. This is a type of market failure that is usually referred to as an environmental "externality." Until recently, virtually the only means of controlling environmental externalities was through "command-and-control" regulation. However, the allowance trading system, created by the Clean Air Act Amendments of 1990 (CAAA), is an attempt to create a national *market* for a specific environmental pollutant, sulfur dioxide (SO_2). It is believed that by creating a market for SO_2 as opposed to regulating by governmental decree, significant cost savings will be realized. Estimates of the savings from the trading system range up to $3 billion annually over what would have occurred with the same SO_2 emission reduction under command-and-control regulation.

Basically, the SO_2 allowance system works as follows: each existing electric generating source of SO_2 is given an allocation of allowances from the federal Environmental Protection Agency (EPA) up to a unit's emissions limit[1] or its actual emissions, whichever is lower. Each allowance permits a source to emit one ton of SO_2 for a specified year. Sources may exceed their emissions limit by acquiring allowances from others in the allowance market. New sources, unless specifically provided for in the Act, must acquire allowances from other allowance holders. There is a national limit of 8.95 million tons of SO_2 per year beginning in 2000; this reduces national SO_2 emissions by 10 million tons below the 1980 level and caps it at that level. Allowances can be traded and any person or organization may purchase and possess them. Sources must comply with the requirements of Title I of the CAAA (National Ambient Air Quality Standards),

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[1] In phase I (1995 to 2000) the limit is 2.5 pounds of SO_2 per mmBtu and applies to 110 plants specifically named in the CAAA. In general, these are plants larger than 100 megawatts (MW) with emissions greater than the 2.5 pound limit. In phase II (after January 1, 2000) the limit is reduced to 1.2 pounds of SO_2 per mmBtu and will apply to all units over 25 MW based on the units' fuel consumption in the years 1985 to 1987 (unless petitioned to be otherwise).

irrespective of the number of allowances they possess.

The potential cost savings of a trading program come from two sources. First, utilities are given more choice as to how they will comply with the Act's emissions requirement. Sources may choose from several control options such as scrubbers, switching to lower sulfur fuel, or repowering the unit, for example. This means that suppliers of these options (scrubber manufacturers, coal suppliers, and so on) are now competing against each other to provide emission reduction options. Also, an additional compliance option is now available to sources--acquiring allowances from the market or from other units on a source's own system. The second source of cost savings is based on the fact that different SO_2 sources have different costs of control. This may be due to better access to low-sulfur coal supply or a unit or plant that can be retrofitted at a lower cost than others. The allowance system provides a means for these lower cost sources to sell to sources with relatively higher emission control costs.

With the market-based allowance system, there is intended to be a direct linkage between the source's compliance costs and the market price of allowances. If a source can reduce its emissions by using control options for a lower marginal or incremental cost (in dollars per ton) than the allowance price, then the option or options should be chosen. If, on the other hand, the marginal control cost is greater than the allowance price, the source should purchase allowances for compliance. Thus, relatively low-cost sources (marginal control costs below the market price of allowances) should be suppliers of allowances and relatively high-cost sources should be purchasers. Ideally, no affected source should be incurring a marginal control cost above the market price of allowances.

Since the Act's passage, there have been about seventeen allowance transactions, the first annual EPA auction was held, utilities settled on their phase I compliance plans, and several state public utility commissions and the Federal Energy Regulatory Commission (FERC) have reacted. The volume of allowances traded thus far (nearly 880,000) is an encouraging signal that the allowance market is developing. However, the majority of the phase I allowances traded have been acquired by two utilities with one utility accounting for over half the total volume. An examination of utility compliance plans also reveals that (with one notable exception) utilities have chosen self-sufficient compliance strategies; that is, they have chosen compliance options that lead to their own system compliance and are not utilizing the allowance market to choose compliance options or take advantage of trading opportunities. The result is that phase-I-affected utilities are incurring much higher marginal control costs than necessary (up to six times the current market price in one region). It is reasonable, therefore, to assume that the full benefits of the trading system are not yet being realized.

Several reasons have been cited as explanations of these results. They include, utility reluctance to try a novel compliance option, political constraints imposed by state interest groups, and regulatory uncertainty. Regulatory uncertainty includes possible actions or reactions by federal and state environmental regulators, the Internal Revenue Service, FERC, and state public utility commissions.

Many observers have noted (including several previous NRRI reports) the particular importance of the public utility commission's role in utility compliance decisions and, therefore, the success (or failure) of the allowance trading system. Under command-and-control environmental regulation, the primary responsibility for implementation of the requirements was delegated to the federal and state environmental regulators. However, the allowance trading system is being applied to electric utilities that are economically regulated. As a result, a major part of the responsibility for implementation shifts to the economic regulators, that is, state commissions and FERC.

The most common state commission activity to date has been the review, and in many cases approval, of utility compliance plans. Nearly all states with phase-I-affected units have reviewed compliance plans, either as part of a broader integrated resource plan or as a separate compliance plan. With respect to the ratemaking treatment of allowances and compliance costs, those commissions that have indicated a preference, have chosen to use automatic passthrough provisions in many cases. Also, in most cases (again, where the issue has been addressed) commissions have indicated that the revenue or gain from the sale of allowances should be exclusively given to ratepayers. In general, commissions are applying traditional ratemaking measures to implement the allowance program.

As previous NRRI reports and others have indicated, under a traditional regulatory approach utilities will not be encouraged to use the allowance system in the best interest of ratepayers. For utilities that have relatively high control costs and compliance requirements, traditional regulation does not encourage a utility to minimize its compliance cost, including purchasing allowances when it is cost-effective. A utility in this situation is more likely to favor a self-sufficient compliance strategy, since it presents fewer market risks and costs are likely to be passed through to ratepayers. For utilities that have low marginal control costs and emission reduction requirements, that is, utilities that have an opportunity to cost-effectively sell allowances, there is little incentive to incur the risk this type of strategy would entail. This is because the utility may fear that it would realize little or none of the benefits and that the additional costs may not be recoverable.

Evidence that traditional regulation to date has not meshed very well with CAAA implementation includes (1) utility phase I compliance decisions with marginal compliance costs substantially above the market price of allowances, and (2) the fact that few utilities have taken the opportunity to purchase allowances. As noted, for the most part utilities have chosen to generate and use allowances within their own system and are eschewing the allowance market, that is, forgoing the opportunity to sell to or purchase allowances from outside sources.

Thus far, no commission has adopted a review and ratemaking procedure that establishes a link between the market price of allowances and compliance costs nor have they encouraged their utilities to do so. In general, the issues of finding a least-cost compliance plan and determining a ratemaking treatment have been dealt with separately. There are, however, alternative regulatory procedures to traditional approaches that do make this link between costs and the allowance market and may, therefore, be more compatible with the allowance system.

One such method uses the market price of allowances as the basis for cost recovery. The commission could determine a benchmark standard based on the market price of allowances. This could be set annually, for example, at the beginning of the year. If the utility's compliance costs were below the benchmark, the utility would recover their actual cost plus some predetermined portion of the difference. If, on the other hand, the utility's compliance costs exceeded the benchmark, it would recover only the benchmark and perhaps some portion of the difference. Thus, the utility has an incentive to adopt compliance options that are cost-effective, including the purchase of allowances. The utility will overcontrol its system only when it is cost-effective to do so--when its marginal control costs are below the market price (or benchmark) of allowances.

Under this approach, the commission would adjust the benchmark periodically to ensure that it accurately reflected the utility's buying and selling opportunities. Also, the commission would have to determine the utility's actual marginal SO_2 control costs. Detailed review of the utility's entire compliance plan would no longer be necessary. The commission would, however, have to monitor the program to ensure that it performs as intended--that is, it is leading the utility to adopt cost-minimizing solutions.

Thus far, both utilities and their ratepayers have realized some of the benefits from the allowance trading system. This is primarily from the flexibility that utilities now have when developing a compliance strategy and the ability to transfer allowances within their own system. Additional cost savings could be had with a regulatory treatment that encourages economic external trading as well. Ratepayers would most likely benefit if commissions were to establish a ratemaking treatment that is more compatible with the allowance trading system and encouraged utilities to use the market more effectively.

If the traditional regulatory approach is followed through to its logical conclusion, then many of the current phase I utility decisions are likely to be questioned retrospectively in rate cases and prudence reviews. A preferable method may be to adopt an approach that encourages appropriate adjustments to current compliance plans and leads to more economical utility decisions in the early stages of the phase II decisionmaking process.

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FOREWORD

This is the fifth report NRRI has published on the topic of public utility commission implementation of the Clean Air Act Amendments of 1990. This completes a cycle of Institute work that began when our Board of Directors decided that a major effort should be conducted on the topic in June 1990 (in anticipation of the Act's final passage). As a part of this effort also, the Institute conducted seven workshops on the topic, four of which were co-funded by the U.S. Environmental Protection Agency and the U.S. Department of Energy.

This report is focused on the topics of evaluating utility compliance strategies and the regulatory treatment of compliance costs and emission allowances. These topics have become particularly important as federal and state environmental regulators turn to allowance trading programs as a more cost-effective means to protect the environment. The actions of state public utility commissions will be a major factor in determining the success or failure of these programs.

Douglas N. Jones
Director, NRRI
Columbus, Ohio
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CHAPTER 1

INTRODUCTION

Title IV of the 1990 Clean Air Act Amendments (CAAA) has mandated significant reductions in emissions of the precursors to acid rain--sulfur dioxide (SO_2) and nitrogen oxides (NO_x)--from electric utility power plants. The legislation promotes a market-based approach to environmental regulation, in that different affected sources (power plants) will be allocated specific annual quantities of tradeable pollution permits called emission allowances. One emission allowance permits the holder to emit one ton of SO_2. A utility that owns an affected source must hold enough emission allowances to cover each year's emissions. The utility has the flexibility to consume, sell, or save its allowances. If a utility is able to reduce emissions below its level of allowances, it can sell the surplus allowances or bank them for future use. A detailed discussion of Title IV and the emission allowance program can be found in an earlier report from The National Regulatory Research Institute.[1]

The allowance system has the potential to substantially reduce the costs of compliance for both low and high emission-reduction-cost utilities. Low-cost utilities could gain from selling allowances at a price higher than their cost to produce or release these allowances. High-cost utilities could save money by buying allowances for a price that is less expensive than their own SO_2 reduction costs. Some have predicted that an effective allowance market could reduce the national costs of compliance by as much as $3 billion per year.[2] Whether the allowance market develops and such savings are

[1] Kenneth Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, 1992), Chapters 1 through 3.

[2] Paul R. Portney, "Policy Watch: Economics and the Clean Air Act," *Journal of Economic Perspectives* 4, no. 4 (1990): 173-81. A more recent and similar estimate is in Electric Power Research Institute, *Integrated Analysis of Fuel, Technology and Emission Allowance Markets: Electric Utility Responses to the Clean Air Act Amendments of 1990*, EPRI TR 102510 (Palo Alto, CA: Electric Power Research Institute, November 1993).

realized will significantly depend on the regulatory policies that are adopted by public utility commissions in implementing Title IV.

State utility commissions have some complicated decisions to make during the implementation of Title IV. First, each affected utility's compliance strategy will have to be reviewed. This will likely entail an assessment of the validity and/or prudence of the utility's choice of compliance options. Second, utility regulatory commissions will have to determine how the costs of these compliance options will be recovered. This report touches on both areas but primarily focuses on the second. The report's intention is to help commissions answer, or at least explore, the following questions:

1. What regulatory approaches might be implemented to encourage utilities to pursue least-cost compliance strategies?
2. What types of complications are associated with different regulatory approaches?
3. How should emission allowances be factored into regulatory decisions?
4. How might different approaches affect utility stockholders and therefore utility decisionmaking?
5. How might different approaches affect the welfare of ratepayers?

This report examines different regulatory approaches that could be adopted in recovering the costs of compliance with Title IV and in allocating the gains or losses associated with the purchase or sale of emissions allowances. Particular emphasis is placed on exploring the effects that different regulatory treatments may have on utility decisionmaking. Through the selection of specific approaches, a regulatory commission may intentionally or inadvertently bias a utility's compliance decisions. A framework for describing various regulatory approaches is presented and is used to structure the discussion of three specific ratemaking treatments.

Although most phase-I-affected utilities have decided on their basic compliance plans, it is reasonable to expect that they will be making adjustments to these plans as circumstances change.[3] In addition, phase-II-affected utilities are beginning to evaluate their options. Therefore, it is essential that regulatory commissions adopt sensible regulatory treatments that will positively influence these utilities' decisionmaking processes.

The remainder of this chapter discusses the compliance planning context, primarily focusing on the range of options utilities now have and the factors that may guide a decision. Chapter 2 provides an update on utility phase I actions, the allowance market, and regulatory responses. Chapter 3 examines the procedures for developing or evaluating a compliance strategy. Chapters 4 through 7 discuss regulatory accounting and ratemaking issues.

Compliance Planning: The Context

Need and Scope

The need for compliance planning arises from the requirements imposed by the CAAA. The CAAA allows a wide range of options to meet the compliance requirements of the Act. The options are also interdependent: the choice of an option at one affected unit will likely affect the choice at another unit. Furthermore, the allowance market mechanism makes compliance requirements interchangeable between units--allowance credits from overcompliance at one unit can be used to offset allowance shortfalls due to undercompliance at another unit. This offers a utility significant flexibility in choosing compliance options for individual units. This also allows the utility to treat its compliance requirements on a systemwide, rather than unit-specific basis. The diversity and interdependence of the available options, and the flexibility offered by

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[3] The most dramatic change since the Act's passage is the price of allowances, which is now less than one-third the price forecasted in late 1990 and early 1991 ($600 to $700 down to less than $200 in late 1993).

the use of a systemwide treatment of compliance requirements, warrant a comprehensive and well-integrated, rather than a piecemeal, approach to meeting compliance goals.

However, the diversity and interrelatedness of options, so far as they directly address the compliance requirements of the CAAA is but a part, although not an insignificant part, of the complexity that confronts the task of utility resource planning. In addition to considering the requirements set by the CAAA, the utility planner needs to consider other utility needs and goals that interact with the choice of compliance options. Some of the more important needs and goals are meeting anticipated future power demand, maintaining system reliability, and ensuring the utility's financial health.

It is useful to look at compliance planning as an extension of traditional utility planning. Traditional or precompliance utility planning involved forecasting future demand and prices of fuel and other inputs, and developing a combination of generation, power purchases, and as a result of later developments, demand-side options to meet the demand at the lowest achievable cost. Compliance planning extends the planning process by imposing new constraints in the form of environmental requirements and adding new decision variables in the form of compliance options.[4]

Further, given the fact that any planning exercise requires a forecast of the future, compliance planning is subject, at the very least, to the same set of uncertainties and risks (associated with future demand, prices, system performance, regulatory treatment, and so on) that has traditionally been a part of utility planning. New constraints and decision variables that accompany compliance planning introduce new sources of uncertainty (performance of pollution abatement technologies, allowance prices, and so on). Finally, the traditional and new decision variables interact, widening the uncertainties associated with both sets of variables.

Therefore, while compliance planning may be visualized as an extension of traditional utility planning, it must be emphasized that the extension is hardly linear or simple. Regardless of the sophistication to be achieved and the level of detail to be included in any given compliance plan, the planner must remain responsive to the broader context defined by the relationships and

[4] Electric Power Research Institute, *Clean Air Response: A Guidebook to Strategies* (Palo Alto, CA: Electric Power Research Institute, December 1990), RP 3199-1.12

interactions among two sets of variables and constraints; the variables associated with specific compliance goals per se, and the more general objectives of the utility.

Range of Available Options

The CAAA allows electric utilities a wide range of options to comply with its SO_2 requirements. There are several ways to classify compliance options into categories. The simplest classification would be into pollution control technologies and others. But it may be analytically more helpful to classify them by outcome than by their individual features. Thus, they may be classified as options that directly reduce emissions (including both emission control technologies and modifications to the power generation process), options that modify power generation requirements, and the purchasing of allowances (Figure 1-1).

Compliance options that directly reduce emissions can be divided into options for existing plants and options for new plants. The existing plants can be scrubbed (scrubbing is also known as flue gas desulfurization or FGD), repowered with clean coal technologies (CCTs),[5] or fueled with cleaner fossil fuels, such as low-sulfur coal or natural gas (known as fuel switching). For new plants, a utility can use cleaner fossil fuels, CCTs or nonfossil fuel technologies (renewables and nuclear). For both existing and new plants, emissions of SO_2 and other criteria pollutants can also be reduced by changing the dispatch order of plants (emissions dispatching).

Compliance options that reduce emissions by modifying generation requirements consist of load management, conservation, and other demand-side management (DSM) options. DSM options can be used to reduce emissions on both the existing and the future generation system.

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[5] Repowering consists of modifying or replacing the boiler of a fossil-powered plant with improved thermal efficiency and pollution control features.

Fig. 1-1. Range of clean air compliance options.

(Source: Authors' construct.)

Finally, trading of allowances, allows a power generator with relatively low SO_2 control costs to generate excess allowances (beyond the CAAA requirement) and economically sell such allowances to another power generator with higher SO_2 control costs. Purchasing allowances, unlike other options, does not involve any action to alter or adjust system operation. Nor does it directly involve any resource acquisition choices. However, the price of allowances serves as a benchmark against which other compliance options may be evaluated. Therefore, allowance trading serves the role of facilitating more efficient compliance choices across sources.

Appendix A presents a brief overview of specific compliance options.

Factors Governing the Choice of Options

A utility's choice of compliance options depends on a number of factors. The factors may serve as criteria by which compliance options are evaluated and ranked. Cost is obviously a critical factor. Other important factors are technological feasibility, revenue earning potential, expected allowance prices, and regulatory treatment.

Technological Feasibility and Performance History

The compliance requirements of individual utilities, as well as the compliance requirements of different plants within the same utility system, may vary. The effectiveness of a particular pollution control technology for a particular plant may depend on the plant design, the fuel type, and the pollutant involved. For a given combination of plant design, fuel type, and pollutant, control technologies can be compared on the basis of performance indices, such as the removal efficiency and the thermal efficiency (heat rate). Comparison of control technologies may involve a tradeoff between predictability of performance and quality of potential performance. For example, scrubbers impose a thermal efficiency penalty on the plant because of the additional energy needed to operate the scrubber. A repower technology, such as a CCT, on the other hand, is expected to improve the thermal efficiency of a coal-fired plant. However, the performance of a scrubber is more predictable (because of the technology's relatively long operating history) than the performance of a repower technology. Therefore, a utility may choose a control technology with inferior but predictable performance over another technology with superior but uncertain performance.

Cost

Perhaps the most important determinant of the adoption of a compliance option is its total cost over a planning horizon. To rationally compare costs of various compliance options, the costs need to be normalized to some standard baseline. One commonly used method calculates the present worth of a stream of expenditures over a given period, by discounting each year's expenditures to the current year. Another method, known as cost levelization, calculates a stream of uniform annual expenditures whose total is equal to the total of actual expenditures. It is important to ensure that a consistent cost estimation method that is uniform across options is used to compute and compare various options.[6]

Revenue Earning Potential

Some of the options may generate additional revenues for the utility. The obvious example is, of course, the potential revenues to be earned from the sale of allowances. If regulatory treatment allows a utility a part of the earnings from the sale of allowances, this becomes an attractive option for utilities. A secondary result of such regulatory treatment is that technologies that overcontrol emissions (for example, scrubbers) and that generate bonus allowances (for example, commission-approved DSM options and renewables) also become considered options. If, however, the earnings from the sale of allowances are mostly flowed back to ratepayers, then the utility may have little incentive to sell and therefore generate allowances through the use of overcontrol, DSM, and renewable generation options. In that case, the

[6] In this report, the cost levelization method is used to compare options. This method is discussed in more detail in Chapter 3.

compliance choice is more likely to be governed by cost considerations alone.

Another source of revenue to the utility may be the sale of byproducts generated by a control technology (such as gypsum). Currently, there are several regenerable control technologies in operation and others are being developed. Technologies which generate byproducts also may significantly reduce the production of solid and liquid wastes which are also subject to environmental regulation. This also offsets the cost of abatement for such technologies.

Expected Allowance Prices

Another critical factor governing the choice of an option in a compliance strategy is the expected future price of allowances. As previously stated, a utility should use compliance options that have unit incremental costs lower than the allowance price. If the combination of such options meet or exceed the compliance requirements, any excess allowances can be sold by the utility. If all such options are exhausted and still the utility falls short of meeting compliance requirements, it should meet the remaining requirements through the purchase of allowances.[7]

Although this is a sound rule well-grounded in economic theory,[8] the unpredictability of future allowance prices (in addition to other uncertainties) may make it hard to implement the rule in practice.[9] A utility whose forecast of allowance prices deviates significantly from actual prices may face adverse consequences if the utility's compliance plan is relatively inflexible and cannot respond to fluctuations in allowance prices. A utility may attempt to address this possibility by requesting a strong commission commitment to the utility's compliance plan to ensure recovery regardless of future allowance prices.[10]

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[7] Use of this rule to compare and rank compliance options is illustrated in Chapter 3.

[8] See Rose, *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program*, Chapter 3.

[9] See Chapter 3 for approaches to treat uncertainties in compliance planning.

[10] As will be discussed in Chapter 2 of this report, there have been utility and state initiatives to institute preapproval of utility plans as a response to this uncertainty. Preapproval and its advantages and disadvantages are discussed in Rose, *Public Utility Commission Implementation*

This response to the utility's risk exposure (caused by the uncertainty of allowance prices and other planning parameters) in general, as well as the choice of compliance options, may be largely shaped by regulatory treatment.

Regulatory Treatment

The choice of compliance options is likely to be influenced strongly by regulatory treatment of investments and expenses involved. Traditional rate-of-return (ROR) regulation is characterized by strong oversight and scrutiny (in the form of prudence reviews and application of the used-and-useful standard) and guaranteed recovery of all prudently incurred expenses. In general, there are no additional rewards to the utility for improvements in management effectiveness or successful risktaking.

Such treatment tends to make the utility avoid options which may lead to underrecovery of attendant costs. Generally, it is easier for the utility to recover operating costs and harder to recover capital costs. This may induce the utility to avoid options that have relatively high capital costs. Further, the utility may prefer to invest in options that are tried and proven (lowering technological risk) and have minimum risks of disallowance (minimizing regulatory risk). Furthermore, the guaranteed recovery of prudently incurred expenses does not provide significant inducements to engage in dynamic, flexible, and market-responsive planning. Therefore, the utility may forego options that are lower cost and environmentally more effective in favor of options that are tried and proven.

The resulting set of compliance options may not be the least cost and may not best serve the long-term interests of ratepayers. To ensure that compliance options are chosen to best serve the ratepayer interest and promote the economic efficiency and the environmental goals of the CAAA, a reexamination of ratemaking treatments of compliance options merits strong consideration.[11]

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of the Clean Air Act's Allowance Trading Program, Chapter 6.

[11] More detailed discussion of this issue appears in Chapters 5, 6, and 7 of this report.

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CHAPTER 2

UPDATE ON THE SULFUR DIOXIDE ALLOWANCE TRADING SYSTEM: UTILITY ACTIONS, THE ALLOWANCE MARKET, AND REGULATORY RESPONSES

More than three years have passed since the Clean Air Act Amendments of 1990 (CAAA) were signed into law, and, at this time, there is approximately one year remaining before the beginning of phase I. At this time also, utilities are beginning to consider their strategies for phase II and are, in some cases, already discussing them with their regulators. Since the Act's passage, there have been about seventeen allowance transactions between utilities and others, the first U.S. Environmental Protection Agency (EPA) auction has occurred, phase I compliance plans have been completed by utilities, and public utility commissions have, in many cases, responded. Therefore, it is now possible to examine the allowance market and utility and public utility commission responses and consider ways, if necessary, to make adjustments to facilitate the market's further development.

Utility Phase I Compliance Action

Since the beginning of phase I is only about a year away, most compliance decisions have been made and in many cases approved by the appropriate state commission. By far, the preferred options are fuel switching or blending. Of 109 phase-I-affected plants reported in a recent Electric Power Research Institute (EPRI) survey[1] (out of 110 plants listed in Title IV of the CAAA), sixty-four are switching or blending fuel (59 percent). Flue Gas Desulfurization (FGD or scrubbers) are next at eighteen plants (almost 17 percent). Six plants plan or have switched to natural gas or oil and four are already retired or plan to be retired for compliance. Compliance decisions by plant are summarized in Table 2-1.

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[1] Electric Power Research Institute, *Integrated Analysis of Fuel, Technology and Emission Allowance Markets: Electric Utility Responses to the Clean Air Act Amendments of 1990,* EPRI TR 102510 (Palo Alto, CA: Electric Power Research Institute, November 1993).

The twenty-one plants that plan no action are either already in compliance (often as a result of an earlier state environmental requirement) or plan to shift allowances from a plant or plants that will overcomply within the utility's own system. Only three plants, that are part of the same utility system (Illinois Power Company), are meeting

TABLE 2-1

UTILITY PHASE I COMPLIANCE ACTIONS BY PLANT

Coal switching or blending	64
No action[2]	21
Flue Gas Desulfurization (FGD)[1]	18
Switch to natural gas or oil	6
Retired or retiring	4
Purchase allowances[3]	3
Total plants[4]	109[5]

Source: EPRI, *Integrated Analysis of Fuel, Technology and Emission Allowance Markets,* Appendix B, Table B-10.

[1] Four plants are both coal switching and building FGD facilities.
[2] Compliance covered by other plant actions or already in compliance due to earlier action(s).
[3] Also coal blending at these plants.
[4] Plants identified in EPRI survey. Other plants many also be affected phase I units as substitution units.
[5] Column does not sum to 109 because of multiple options being chosen at some plants.

compliance primarily by acquiring allowances.[2] Other utilities are using purchased allowances to supplement what are mostly fuel-switching or blending strategies.

Actual phase I compliance costs are difficult to come by. Often these numbers are not reported in compliance plan filings or are presented in a manner that makes it difficult to determine whether the numbers are average or incremental cost. Estimated regional cost figures are available, however, from the recent EPRI study.[3] EPRI did not collect actual compliance cost figures for their analysis, but used a simulation of individual plant and system costs for a given compliance action combined with known phase I compliance choices. These simulated cost figures are presented in Table 2-2.

The results show a wide variance in compliance costs across regions. Average phase I reduction costs (1992 dollars per ton) are the lowest[4] in the MAIN[5] region at $118 and highest in the NPCC[6] region at $700. Average reduction costs, however, can be misleading, particularly when such large geographic areas with many utilities are included in the calculation. Marginal or incremental costs, can provide a better indication of how well the allowance program is working when compared with the allowance market price.

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[2] Illinois Power Company's system compliance strategy has three main components: (1) reduced utilization of phase-I-affected units (through emissions dispatching),
(2) substitution of a unit as a phase-I-affected unit, and (3) the acquisition of allowances from other sources by designating transfer and substitution units with other utilities and purchasing allowances from other sources.

[3] Electric Power Research Institute, *Integrated Analysis of Fuel, Technology and Emission Allowance Markets*, Appendix C.

[4] Excluding Texas (ERCOT--Electric Reliability Council of Texas) and western states (WSCC--Western Systems Coordinating Council) that do not have phase I units.

[5] MAIN (Mid-America Interconnected Network) is a North American Electric Reliability Council (NERC) region consisting of Illinois, most of Wisconsin, eastern Missouri, and the upper peninsula of Michigan.

[6] NPCC (Northeast Power Coordinating Council) includes all of the New England states and most of New York state.

TABLE 2-2

ESTIMATED PHASE I AVERAGE AND HIGHEST MARGINAL EMISSION REDUCTION COSTS FOR COMPLIANCE CHOICES IN RELEVANT NERC REGIONS
(1992 dollars per ton)

NERC Region[1]	Average Cost[2]	Marginal Cost[3]
NPCC	700	932
MAAC	439	767
ECAR	313	1,147
MAIN	118	395
MAPP	184	332
SERC	270	541
SPP	184	377
U.S.	284	1,147

Source: EPRI, *Integrated Analysis of Fuel, Technology, and Emission Allowance Markets*, Appendix C, Table C-1.

[1] Northeast Power Coordinating Council (NPCC), Mid-Atlantic Area Council (MAAC), East Central Area Reliability Coordination Agreement (ECAR), Mid-American Interconnected Network, (MAIN), Mid-Continent Area Power Pool (MAPP) Southeastern Electric Reliability Council (SERC), and Southwest Power Pool (SPP). Texas (ERCOT) and western states (WSCC) are not included since they have no phase-I-affected units.
[2] Includes the cost of banking allowances for use in phase II.
[3] The marginal cost for the most expensive phase I compliance option selected by a utility in the region.

Marginal costs (the highest regional marginal costs for selected phase I options) are lowest in the MAPP[7] region at $332 and highest in the ECAR[8] region at $1,147. This compares with an allowance price by a recent survey[9] of $188 for phase I allowances in October of 1993. The ECAR regional marginal compliance cost, therefore, is more than six times the current going rate of allowances. No region had a marginal cost at or below the current allowance price. (Also, note that four out of the seven regions had *average* reduction costs greater than allowance prices.) These regional marginal costs can also be misleading since they reflect a single unit within the specific region that may not be representative of the entire region. These aggregated data suggest, however, that at the very least, some opportunities to purchase allowances have not been taken. Less aggregated data (plant level, for example) would better indicate the extent to which these opportunities are being missed and higher-than-necessary control costs incurred.

The Allowance Market

Private Trades

Most allowances traded to date have been through private transactions between buyers and sellers and, in some cases, with a broker or intermediary facilitating the transactions. Table 2-3 summarizes the publicly announced allowance transactions to date. The quantity reported in the table is the total contracted quantity (unless otherwise noted). The duration of most contracts exceed one year of phase I.

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[7] MAPP (Mid-Continent Area Power Pool) includes Iowa, western Wisconsin, Minnesota, North Dakota, (most of) South Dakota, Nebraska, and extreme eastern Montana.

[8] ECAR (East Central Area Reliability Coordination Agreement) includes most of Michigan and Kentucky, Indiana, Ohio, West Virginia, and parts of western Virginia, Maryland, and Pennsylvania.

[9] From Fieldstone Company, Inc., *Compliance Strategies Review* (Washington, D.C.: Fieldstone Company, Inc., November 8, 1993), 3.

TABLE 2-3

PUBLICLY ANNOUNCED ALLOWANCE TRANSACTIONS TO DATE

Date[1]	Seller	Buyer	Quantity	Price[2] ($)
May 1992	Wisconsin Power and Light Co.	Tennessee Valley Authority	10,000	250
	Wisconsin Power and Light Co.	Duquesne Light Company	15,000-25,000	276
June 1992	Alcoa Corp.	Ohio Edison	25,000	250-350
March 1993	Northeast Utilities	American Lung Association	10,000[3]	Donated
	LILCO	AMAX Energy	--[*]	--
	UI	WEPCO	5,000[4]	--
	CIPS	Illinois Power[5]	80,000	--
April 1993	--	Illinois Power	125,000 (option)	--
	--	Illinois Power	90,000	--
	PacifiCorp	Illinois Power	35,000 (approx.)	--
	WEPCO	Illinois Power	75,000	[6]
	NYSEG	Illinois Power	6,000-8,000	[7]
	--	Illinois Power	50,000	--
May 1993	Big Rivers/ Henderson MP&L	Centre Financial	150,000	178

TABLE 2-3

PUBLICLY ANNOUNCED ALLOWANCE TRANSACTIONS TO DATE

Date[1]	Seller	Buyer	Quantity	Price[2] ($)
July 1993	Big Rivers/ Henderson MP&L	AMP Ohio	4,384	205
Sept. 1993	WEPCO	PSI Energy	37,000	200-210
Oct. 1993	Centre Financial	CP&L	150,000	--

Sources: Fieldstone Company, Inc., *Compliance Strategies Review*; John Metzler, ENRON Corp., August 1993, personal communication; and EPRI, *Integrated Analysis of Fuel, Technology and Emission Allowance Markets*.

[1] Announcement date may differ from when transaction actually occurred.
[2] Reported prices should only be considered approximate. Figures presented are a range, first year of contract price, or an average price for the contracted years.
[3] Phase II allowances.
[*] -- indicates information was undisclosed.
[4] Agreement is an option for 5,000 per year for an undisclosed number of years beginning in 2000.
[5] EPRI (July 1993) reports that for approximately 433,000 allowances, Illinois Power's average cost was $197 per allowance (in 1995 dollars).
[6] Swap of 75,000 phase II allowances plus a fee.
[7] Designated transfer units.

The total volume of private trades in these transactions is nearly 880,000 allowances in seventeen transactions. Since there will be approximately 27.5 million allowances in all five years of phase I, this represents about 3 percent of all phase I allowances.[10] Illinois Power Company (IP) accounted for seven of the seventeen trades and over half of the total volume. When the two largest participants (by volume of allowances purchased) are subtracted from the total, IP at 462,000 and Carolina Power & Light (CP&L) at 300,000,[11] the volume then drops to 118,000 allowances or less than one-half of 1 percent of the total phase I allocation. The allowance market, therefore, can be characterized as a "thin" market at this time.

Caution should be exercised when examining these transactions since they only represent publicly announced transactions. There are some indications that other transactions have occurred but were kept confidential. Also, at this time, some believe other, perhaps many, transactions are "in the works." However, these claims are supposition and cannot be verified at this time, nor can it be determined how many or what volume of allowances this may represent.

Also the price of allowances presented here should be examined with some care. As with other contract arrangements of this type, contract terms often include purchase options, are for multiple years, and contain various safeguard clauses. These clauses may include a provision to change a price in the future if the market price differs by a predetermined amount. Also, in general, the more flexibility the buyer receives, the higher the price. These and other contract provisions will affect the price and make it

[10] These numbers should only be considered a rough approximation.

[11] The 300,000 allowances results from counting the 150,000 purchased by Centre Financial from Henderson MP&L and then sold to CP&L as one transaction. They are presented in the table as the two separate transactions they in fact were. The 150,000 phase I allowances purchased by CP&L is the second largest known transaction, after the IP arrangements. It is interesting to note that CP&L is a utility with only phase-II-affected plants. Nevertheless, CP&L has been acquiring phase I allowances for its compliance in phase II.

difficult to determine a "going price." Also, there is price information for only six out of the seventeen transactions.

EPA Auction Results

The EPA is required by the CAAA to hold an annual allowance auction. The allowances for the auction come from a reserve created by reducing affected sources' allocations by 2.8 percent.[12] Congress created the auction provision to facilitate the development of a private allowance market. The auction is open to all interested parties, is a sealed bid auction with the sale based on the bid price, and has no minimum bid. Auction proceeds or unsold allowances are transferred back to affected units contributing to the reserve on a pro rata basis. Any holder of allowances may submit allowances and specify a minimum price for sale in the auction. These "private offers" are sold after the EPA-held allowances have been auctioned. EPA is required to make public the prices and results of each auction.

EPA designated the Chicago Board of Trade (CBOT) to conduct the first auction that was held on March 29, 1993. The auction, by CAAA design, was split into a "spot auction" made up of 50,000 year 1995 allowances and an "advance auction" composed of 100,000 year 2000 allowances. Table 2-4 shows the result of the spot auction and Table 2-5 presents the results of the advance auction. The CBOT plans to hold the second auction in March of 1994.

Only eight investor-owned utilities (IOUs) were successful bidders in the spot auction. These IOUs purchased almost 93 percent of all allowances sold in the spot auction. The lowest successful bid price was $131 and the highest bid price paid was $450. The highest price paid by an IOU was $201. The weighted-average price for all

[12] The reserve is also for direct sales contingency to provide nonutility sources access to allowances. These allowances are available for sale beginning at $1,500 per allowance and are adjusted for inflation.

TABLE 2-4

RESULT OF FIRST EPA "SPOT AUCTION" (1995 ALLOWANCES)

Purchaser	Quantity	Price Paid or Range ($)
Carolina Power & Light Company	13,083	132 - 171
Kentucky Utilities Company	12,900	151 - 201
PSI Energy, Inc.	10,000	151
Illinois Power	5,000	175
American Electric Power Service	3,788	131 - 151
Cantor Fitzgerald	2,572	170
Hoosier Energy REC, Inc.	1,000	150 - 200
Mississippi Power Company	972	138
Gulf Power Company	446	156
Savannah Electric & Power Co.	139	150 - 173
Jemison Investment Co., Inc.	93	141 - 152
Others	17	150 - 450
Total[1]	50,010	131 - 450

Source: Authors' construct from data received from Chicago Board of Trade, April 1993, personal communication.

[1] This total includes the 50,000 allowances from the EPA sales and auction reserve and 10 allowances sold from a private participant (sold after EPA reserve allowances were sold out).

TABLE 2-5

RESULT OF FIRST EPA "ADVANCE AUCTION" (2000 ALLOWANCES)

Purchaser	Quantity	Price Paid or Range ($)
Carolina Power & Light Company	72,020	122 - 171
Duke Power Company	25,000	147
Cincinnati Gas & Electric Co.	1,234	128
Gulf Power Company	709	141
William Herrington	630	126 - 171
Paul Wedel	300	151
Emissions Exchange Company	100	240
Other	7	125 - 310
Total[1]	100,000	122 - 310

Source: Authors' construct from data received from Chicago Board of Trade, April 1993, personal communication.

[1] This total includes the 100,000 allowances from the EPA sales and auction reserve. No allowances were sold from private participants.

bidders was \$156.63. All 50,000 of the EPA-retained allowances and 10 allowances from private offers were sold. Spot offer prices were between \$10 and \$1,900.

All offer and bid prices and quantities, both successful and unsuccessful, are plotted in Figure 2-1. These are, in effect, supply and demand curves from the auction data. S_{epa} is drawn as a perfectly inelastic supply curve since there is no price requirement with the quantity set at 50,000. The private offers are represented by the S_{po} curve and the bids are represented by the curve D_s. The private supply curve is very inelastic, with the price rising relatively quickly with quantity (at 5,010 the price is \$210). Demand, in contrast, is much more elastic. This difference reflects the caution used by participants when selling their own allowances and using a "bargain hunting" manner when bidding.

In the advance auction of 100,000 year 2000 allowances, only four IOUs were successful bidders. Two utilities, CP&L and Duke Power Company, purchased over 97 percent of the total number of allowances sold. The lowest successful bid price was \$122 and the highest was \$310. The weighted-average price of the successful bids was \$136.19. All EPA-retained allowances were sold with no private offer allowances being sold. Advance offer prices were between \$200 and \$449.

All offer and bid prices and quantities, both successful and unsuccessful, are plotted for the advance auction in Figure 2-2. This demonstrates that bidders and offers were again using a similar strategy as in the spot auction, that is, using caution with their own allowances and bargain hunting when bidding.

Regulatory Action

In the three years since the CAAA was passed, state commissions and the Federal Energy Regulatory Commission (FERC) have begun to form regulatory policies or react to specific utility actions. To date, state commission actions have mostly been in reaction to utility activity. For example, the most common response by state public utility

Fig. 2-1. Spot auction offers (supply) and bids (demand).

Fig. 2-2. Advance offers (supply) and bids (demand).

commissions has been to review, and in some cases, approve utility compliance plans.[13] Utilities have submitted their compliance plans for approval or review and, after review and perhaps some modification, most commissions with phase I utilities have responded. Often this review process has been part of an integrated-resource or least-cost planning (IRP) process. Some utilities with relatively sizable compliance costs, however, have submitted a separate plan that considers proposed compliance actions only.

Several state legislatures have enacted laws that require their public utility commission to consider utility compliance plans[14] and act on their disposition. Sometimes the commissions are restricted as, for example, when the legislation is designed to encourage continued in-state coal use. These legislative activities and public utility commission actions are summarized in Appendix B.

A second state commission reaction has been to issue a rule or order after a utility has been involved in an allowance transaction or has requested approval to enter a transaction. Since, as described above, allowance market activity has been limited to a few utilities, there are currently only a few responses to examine. However, these actions may be an indication of the type of actions that other state commissions will take when transactions occur in their states by their jurisdictional utilities.

A third form of state commission action has been to issue general guidelines on the ratemaking and/or accounting treatment of allowances and compliance costs. This is a more proactive approach that only a few states have, thus far, taken.

The following discussion briefly describes several state commission actions that have occurred so far. The actions described below deal specifically with actions that involve allowance ratemaking and accounting treatment.

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[13] The term "compliance plan" is used here to refer to a plan that is submitted to a commission for review or approval. This may or may not be the same plan submitted to the federal EPA as required under the CAAA.

[14] For example, Florida, Illinois, Indiana, Kentucky, Ohio, and Pennsylvania.

General Guidelines

Three states (Ohio, Pennsylvania, and Iowa) have adopted general guidelines that give utilities an indication of the ratemaking and accounting treatment of allowances.[15] All three focus on the transfer of allowances by utilities in their state and indicate a preference for using automatic passthrough mechanisms for allowance costs.

Ohio

Ohio issued guidelines[16] regarding the ratemaking and accounting treatment of allowances. The guidelines encourage utilities to trade allowances when "economically justified." They require utilities to provide a status report on allowance trading plans. This includes participation in the market and the level of allowance holdings or "banked" allowances. Allowance trading activity will be reviewed in the Electric Fuel Clause mechanism (a fuel-adjustment-clause procedure). The guidelines require utilities to document "trading opportunities or justify trades that did take place and provide sufficient justification for any decision to forego trading opportunities."[17]

Banked allowances will be valued in inventory on a weighted-average basis (unless, the guidelines state, the Internal Revenue Service adopts a serialization approach to valuation). Gains or losses from allowance transactions are to flow through to ratepayers (on an energy, or

[15] Two other commissions, Georgia and New York, have had proceedings and are investigating trading, usage, and ratemaking issues related to allowances. These investigations may also lead to guidelines being adopted.

[16] Public Utilities Commission of Ohio, "In the Matter of the Commission's Investigation into the Trading and Usage of, and the Accounting Treatment for, Emission Allowances by Electric Utilities in Ohio," Case No. 91-2155-EL-COI, January 20, 1993.

[17] Ibid.

kilowatthour (kWh), basis[18]) unless the utility created the allowances using utility "below-the-line" resources. When rates reflect assets and increased operating expenses to free allowances for sale, the revenue is to flow through to ratepayers.

The guidelines state that "[t]he Commission is open to all reasonable incentive proposals and will evaluate proposals on a company by company basis."[19] The Ohio Commission acknowledges that "incentives may encourage allowance transactions and provide benefits which are in the public interest." This does not include "speculative transactions with allowances utilizing ratebased revenues."[20]

Pennsylvania

The Pennsylvania Public Utility Commission adopted a policy statement[21] on allowance treatment. The statement is divided into two main sections: one focusing on approval of compliance plans and the other focusing on the ratemaking treatment of allowances. As required by a Pennsylvania State law,[22] the Commission will review and, if accepted, approve a utility's compliance plan and any planned allowance transactions. The Commission states that it will not approve specific allowance transactions. If a utility chooses not to have a plan reviewed and approved, it will then be reviewed when the utility seeks recovery of compliance costs in a rate case or other procedure.

The number of banked allowances will be reviewed as part of the compliance plan review process. The Commission states that the "utility has the burden of proof concerning the

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[18] How this will work is not specified. It appears that the revenue or loss will flow through the fuel-adjustment mechanism.

[19] Supra., note 17.

[20] Ibid.

[21] Pennsylvania Public Utility Commission, "Policy Statement on Clean Air Act Emissions Allowances," 52 Pa. Code SS69.291 - 69.294, order entered February 3, 1993.

[22] Act 27 of 1992, 66 Pa. C.S.A. Section 530 (Supp. 1992).

appropriate number of banked allowances."[23] Also, approval of a utility's banking decision "does not assure a prudency finding for purposes of ratemaking."[24]

The second part of the policy statement asserts that allowances will be valued at original costs for ratemaking purposes--that is, zero cost for allowances originally allocated by EPA, purchase price plus broker fees if purchased, or at "fair market value" if bundled in a power-purchase or other bundled transaction. Allowances are to be considered as fuel inventory for ratemaking purposes and will be ratebased consistent with other operating inventory items. As such, they will earn a return as with other ratebased investments. Similar to the Ohio provision, allowance expenses are to be recovered through the utility's energy cost rate (ECR, or fuel-adjustment mechanism). Gains or losses on allowance transactions will be flowed through to ratepayers in the ECR on an energy (kWh) basis unless the investment or expense was below the line.

Iowa

The Iowa Utilities Board adopted a rulemaking on allowance transactions.[25] This rule is similar to the Ohio and Pennsylvania rule in that allowance expenses are recovered through the energy adjustment clause (EAC, Iowa's fuel-adjustment mechanism). The gains and losses from the sale of allowances are passed through the EAC. Also, the rulemaking adopts a weighted-average cost inventory method. Allowance transactions and compliance plans are to be reviewed in the "annual electric energy supply and cost review." The rule states that "[t]he prudence review of allowance transactions and accompanying compliance plans shall be determined on information available at the time the options or plans were developed."[26] Costs recovered through the EAC

[23] Supra., note 21.

[24] Ibid.

[25] Iowa Utilities Board, "In Re: Clean Air Act Amendments--Allowance Transactions," Docket No. RMU-93-9, issued November 23, 1993.

[26] Ibid.

that are found to be imprudent will be refunded with interest to ratepayers through the EAC. Allowances transferred between affiliated utilities will be valued at fair market value.

The Iowa Utilities Board also adopted an order that accepts many of the FERC accounting rule changes to the Uniform System of Accounts (discussed below);[27] including historical cost valuation of allowances.

Commission Action on the Sale of Allowances

In addition to these general actions, two states have indicated the regulatory treatment of the revenues from the sale of allowances.

Wisconsin

Two Wisconsin utilities have participated in the allowance market (see Table 2-3 above). The Wisconsin Commission found in two separate rate cases[28] that all the revenue from the sale of allowances should be passed through to ratepayers. The Commission found in the WP&L case that the utility had excess allowances because the utility was required to comply with the State's own acid rain law. Since ratepayers have paid and continue to pay the cost of compliance, ratepayers should therefore receive all the benefits from allowance sales.

Also in the WP&L case, the Wisconsin Commission found that current regulatory procedures for evaluating utility compliance and allowance trading are adequate; but they should

[27] Iowa Utilities Board, "In Re: Clean Air Act--Emission Allowances," Docket Nos. RMU-93-1 and NOI-91-1, issued February 12, 1993.

[28] Wisconsin Electric Power Company (WEPCO) rate case, Docket 6630-UR-106 and a Wisconsin Power and Light Company (WP&L) rate case, Docket 6680-UR-107. WEPCO received $100,000 for the transfer to Dairyland Power of sulfur dioxide (SO_2) emission reductions under the Wisconsin Acid Rain law (plus an additional amount for each ton transferred during 1993 and 1994). WP&L sold allowances to the Tennessee Valley Authority and Duquesne Light Company under the CAAA (see Table 2-2 above).

continue to be evaluated to reflect any changing conditions. In a separate Commission finding[29] the Commission restates its position that the benefits from the sale of allowances should flow through to ratepayers because, as found in the WP&L rate case, they are incurring the costs of compliance. The Commission also states that an "actual rate treatment is not ripe for resolution yet." However, the Commission states that it "is willing to review utility incentive proposals for dealing with SO_2 allowance transactions provided it can be demonstrated that substantial additional benefits will accrue to ratepayers."[30]

The Wisconsin Commission endorses (in its Advance Plan 6) the objective of the allowance program to establish a trading market and "will attempt to further it." The Commission notes also that it is "appropriate" to include in avoided cost calculations (for buyback rates paid to nonutility generators) the value of allowances "freed up."[31]

Connecticut

Connecticut's Department of Public Utility Control (DPUC) also reached a decision[32] on an allowance transaction by one of its jurisdictional utilities. The basic terms of the arrangement were that United Illuminating Company (UI) agreed to sell an option to WEPCO for 5,000 phase II allowances per year for an undisclosed number of years beginning in 2000 (see Table 2-3). The DPUC examined the terms of the option sale and determined (after testimony and three days of hearings) that the arrangement "adequately protects UI and its ratepayers."[33] The DPUC

[29] Wisconsin Public Service Commission, "Advance Plan 6," Docket No. 05-EP-6, "Findings of Fact."

[30] Ibid.

[31] Ibid.

[32] State of Connecticut Department of Public Utility Control, "Petition of The United Illuminating Company for Approval of the Grant of an Option to Purchase Sulfur Dioxide Emission Allowances and the Allocation of Revenues Derived Therefrom," Final Decision, Docket No. 92-12-08, March 4, 1993.

[33] Ibid.

examined the "reasonableness" of the selling price and the contract's provision to, if the option is exercised, reset the price after five years if the then current market price differs by a specified percentage.

The DPUC also made a determination on the split of the proceeds from the sale of the allowances between the utility and its ratepayers. UI originally proposed that the split be 77 percent for ratepayers and 23 percent for the Company.[34] This was based on the proportional share of investments contributing toward the surplus allowances. The DPUC found that UI's method of calculating the split overstated the proportion of surplus allowances provided by the Company and decided that *all* of the surplus allowances were provided by ratepayers.

However, the DPUC found that UI is entitled to a portion of the proceeds from the sale of allowances "to the extent they share in the costs and risks of. . .a sale" since it would "be mutually beneficial to both ratepayers and shareholders" if they did so.[35] The DPUC reasoned that ratepayers will be provided with reduced costs and risks from the sale of allowances if shareholder and ratepayer interests are aligned. To do this, the DPUC requires that the Company incur all of the marketing costs of selling allowances. In exchange, the Company will be able to retain a 15 percent share of the allowance sale proceeds. This will, the DPUC believes, give the Company an "incentive. . .to properly market, in terms of aggressiveness and efficiency, surplus SO_2 allowances."[36] Moreover, the DPUC believes that the "sharing will provide the Company with incentives to sell additional surplus allowances."[37] This will only apply to allowances that are in

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[34] This was revised later by the Company to a 78 percent/22 percent split to account for the retention of some allowances by EPA for the creation of allowance reserves mandated by Title IV of the CAAA. See Chapter 1 of Kenneth Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, 1992), for a description of these programs.

[35] Supra., note 33.

[36] Ibid.

[37] Ibid.

excess of conservation bonus and New England Power Pool (NEPOOL)[38] allowances and do not apply to EPA-retained allowances sold in the annual auction. Additional allowances supplied by the Company for sale in the auction are entitled to the sharing, however.[39] The Company will also be responsible for 15 percent of the cost of purchasing allowances.

The DPUC states that this sharing arrangement only applies to the UI/WEPCO contract and any allowances sold by UI in the future (unless the DPUC changes its decision). However, the DPUC also states that "[a]t the time of any future sales, the Company shall provide the [DPUC] with sufficient detail on the transaction so that the prudency and net benefits of such sale can be adequately determined."[40] The DPUC also decided (pursuant to a State law, Public Act 92-106) that the ratepayers' portion of allowance revenues should be used to offset the cost of future environmental compliance.

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[38] NEPOOL has initiated a method to explicitly integrate the value of allowances into the generation dispatch price. See New England Power Pool, *Treatment of Sulfur Dioxide Allowances for NEPOOL Operations and Billing Purposes* (Holyoke, MA: NEPOOL, December 1992). Methods to incorporate the value of allowances in the dispatching price are discussed later in this report. For a discussion of the NEPOOL method see Kenneth Rose, "Critique of *Treatment of Sulfur Dioxide Allowances for NEPOOL Operations and Billing Purposes*" prepared for The New England Conference of Public Utilities Commissioners, May 24, 1993. (This document is available from the author.)

[39] Parties may voluntarily offer to sell allowances in the EPA annual auction. As noted above, only ten 1995 privately held allowances were sold in the first annual auction.

[40] Supra., note 37.

Commission Action on the Purchase of Allowances

Illinois

As noted in Table 2-3, IP has been the most active participant in the phase I allowance market. Additionally, it is also the only utility to use allowances as its main method of complying with the CAAA for its phase-I-affected units. IP considered several alternative compliance strategies and used a set of seven objectives to decide which to choose. They were as follows: (1) to achieve compliance with the CAAA, (2) to minimize the cost of compliance (based on present value of the revenue requirement), (3) to avoid a rate increase related to compliance, (4) to maximize continued use of Illinois coal relative to historical levels, (5) to maximize flexibility, (6) to minimize shareholder risk, and (7) to minimize other environmental impacts including solid waste generated and carbon dioxide emissions. After considering these objectives, IP decided that acquiring allowances was its preferred compliance strategy.[41]

The Illinois Commerce Commission (ICC) is require by State statute (as several other state commissions are) to review and either approve or reject utility compliance plans within six months of a plan's filing. In its order reviewing IP's compliance plan[42] the ICC considered the strategy that the Company proposed rather than pass judgment

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[41] As noted, this strategy for phase I compliance consists of including the value of allowances in the dispatch price of affected units (or "emissions dispatching" explained later in this report), substituting a unit as a phase-I-affected unit, and acquiring allowances from others in the allowance market. Allowances will be acquired by designating transfer units and substitution units with other utilities as well as purchasing allowances.

[42] Illinois Commerce Commission, "Petition for Approval of a Clean Air Act Compliance Plan Pursuant to Section 8-402.1 of the Public Utilities Act," Illinois Power Company, Order 93-0119, September 29, 1993.

on the individual allowance transactions that IP had enter into or proposed.[43] After review by the Commission and its staff, an evidentiary hearing, and testimony, the ICC approved IP's compliance plan.[44]

The Illinois statute also stated that "pollution control devices for the control of SO_2 emissions should be installed at four generating units. . .continuing to use Illinois coal as a fuel source."[45] Two of these generating units are owned and operated by IP (at the Baldwin plant) and the other two are owned and operated by Commonwealth Edison (at the Kincaid plant). The statute also states that "the owners of [the] generating units should be allowed to recover through rates their prudent costs incurred. . ."[46] IP did begin construction of a scrubber for their units, but later decided to defer its completion until phase II. This deferral, rather than the scrubber's cancellation, allowed IP to change its compliance plan to acquiring allowances and still be in conformance with the State statute.

On December 15, 1993 the U.S. District Court for the Northern District of Illinois Eastern Division found that the Illinois statute violated the Commerce Clause of the U.S. Constitution and that IP's Central Illinois Power Company's and Commonwealth Edison's compliance plans were void and that the ICC is permanently enjoined from enforcing the statute.[47] Early indications are

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[43] The financial details of IP's purchases were filed under a confidentiality clause and not made public. IP's purchase of allowances from Central Illinois Public Service Company required ICC's approval of the sale. This is because it involved the transfer of assets from one Illinois public utility to another; allowances and CAAA compliance were not the concern. (This was approved in a separate order, Illinois Commerce Commission, "Request for Authority to Purchase SO_2 Emission Allowances from Central Illinois Public Service Company Pursuant to Section 7-102(b) of the Public Utilities Act," Order 93-0297, September 29, 1993.)

[44] ICC was also required by statute to collect from its utilities information on the acquisition or sale of allowances on a quarterly basis (Illinois Commerce Commission, "Adoption of Reporting Form to Comply with Section 4-305 of the Public Utilities Act," as Amended by P.A. 88-0226, September 29, 1993).

[45] Supra., note 42.

[46] Ibid.

[47] Alliance for Clean Coal v. Ellen C. Craig et al., No. 93-C-4391, (N.D. Ill., December 15, 1993).

that these compliance plans will not be materially affected since the scrubbers were deferred, but they will have to be refiled and reapproved. Even less certain at this time is the affect this court decision will have on the other less stringent State statutes.

Surcharges and Automatic Passthrough Mechanisms

Two states, Florida and Kentucky (see Appendix B), passed legislation that allows recovery of compliance costs through a surcharge mechanism. The 1993 Florida statute allows recovery of compliance costs through an "environmental compliance cost-recovery factor," that is distinct from base rates. Utilities can have costs that are passed through the mechanism included in rate base in subsequent rate proceedings. To date, the Florida Public Service Commission has not had a rulemaking on implementation of the cost-recovery factor: however, two utilities have filed petitions for cost recovery under the mechanism. (An earlier 1992 Florida statute allows preapproval of compliance plans.)

Similarly, the Kentucky statute allows compliance cost recovery through a monthly surcharge. This is designed to allow quick cost recovery for planned scrubbers. The Kentucky Public Service Commission has opened a generic docket on the CAAA. The Commission has also approved a consultant to review compliance plans and manage the application of the surcharge, which will be considered when a case has been filed (none was pending at the time of the survey).

Several state commissions have also proposed or adopted similar mechanisms. The Maryland Public Service Commission decided to use a surcharge mechanism for compliance costs in a Potomac Electric Power case. Also, the District of Columbia Public Service Commission staff endorsed a cost recovery surcharge in a Potomac Electric Power case. In Mississippi, construction work in progress (CWIP) will be ratebased and costs will appear in a monthly "environmental cost recovery rider" (ECO). The ECO will operate on a projected test year and will receive commission review and approval before and after compliance implementation. In addition, the West Virginia Public Service Commission ruled that revenue from the sale of allowances will be deferred and considered in annual fuel proceedings, with proceeds going to ratepayers (similar to those states noted above).

Federal Energy Regulatory Commission

The FERC issued a final rule[48] in March of 1993 on the accounting treatment of allowances. The main features of the accounting treatment of allowances are an historical cost valuation of allowances, a weighted average cost inventory method, and a new account (Account 509) for expensing allowances. The FERC also decided to use fair market value in the valuation of allowances traded between affiliates; a change from the proposed rule.

The final rule, like the proposed rule, states clearly that it is intended to be "rate neutral." The rule states that:

> the objective in adopting this final rule is to provide useful financial and statistical information to regulatory agencies. . . by establishing sound and uniform accounting and reporting requirements for allowance transactions. . .. The final rule is not intended to promote or discourage particular CAAA compliance strategies or to prescribe the ratemaking treatment for allowances.[49]

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[48] Federal Energy Regulatory Commission, "Revisions to Uniform System of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2 and 2-A," Order No. 552, 18 CFR Parts 101 and 201, issued March 31, 1993.

[49] Ibid., 4.

As noted above, an historical cost valuation and weighted-average inventory method have been adopted by several state commissions. Moreover, in some cases, this has also become the basis for ratemaking treatment of allowances.

To date, the FERC has not indicated what its wholesale ratemaking treatment of allowances and compliance costs will be.[50]

Summary of Regulatory Action

From the actions noted, several preliminary conclusions can be drawn concerning rate treatment of compliance costs and allowances. First, there is a distinct preference for automatic passthrough of either compliance costs, allowance costs specifically, and/or gains and losses on allowance sales. This is done either through a fuel-adjustment-type mechanism or a compliance surcharge. Gains on the sale of allowances in most cases (with one exception) will flow through to ratepayers. Second, several states have chosen to use methods first proposed by the FERC accounting rule as the basis for determining ratemaking treatment--in particular, the use of historical cost basis of allowances and the weighted-average inventory method.

Third, with respect to the review process, compliance costs and allowance transactions have been dealt with on a case-by-case basis. All states have, and are likely to continue to review compliance plans on a utility-by-utility basis. These include stand-alone compliance plans and plans that are part of an IRP process. Finally, states with utilities that sell allowances (out of state in particular) are likely to be more careful in reviewing the transaction than states that have purchasing utilities. Although, due to the limited trading activity to date, there are only a limited number of commission reactions to examine. Also, one state has discouraged its utilities from acquiring allowances.

[50] These issues are also discussed in Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program*; and Kenneth Rose and Robert E. Burns, eds., *Regulatory Policy Issues and the Clean Air Act* (Columbus, OH: The National Regulatory Research Institute, 1993).

Other state actions are summarized in Appendix B. Subsequent chapters of this report are concerned with the construction and review of compliance plans and the effect of different commission actions on utility choices.

Is there a Problem with the Allowance Market?

Some observers of the allowance market are concerned about two developments. First, the price of allowances, which was about $200 in the last few trades, is considerably less than the price predicted during the debates about the CAAA. The second development is the relatively low volume of trades. As noted, to date there have been only about seventeen publicly announced trades. While both of these may be different from earlier expectations, neither by itself is a major problem or cause for concern. However, both are symptoms of larger and longer-term problems with the allowance trading program.

It is important to first be clear on the benefits of the allowance trading program. Thus far, it appears to have produced notable cost savings from what would have occurred with a command-and-control environmental program with the same level of SO_2 reduction.[51] These savings have largely been realized through *intra*utility trading and from the effect of competition between compliance options.

In theory, it is expected that the price of allowances should reflect the marginal cost of the last tons of SO_2 removed.[52] In reality, of course, perfection should not be

[51] The magnitude of the cost savings depend, of course, on the type of command-and-control environmental regulation that the trading program is compared to. See T. H. Tietenberg, *Emissions Trading: An Exercise in Reforming Pollution Policy* (Washington, D.C.: Resources for the Future, Inc., 1985).

[52] The basic economics behind the allowance trading program are discussed in Chapter 3 of Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program*. A more detailed description is in Tietenberg, *Emissions Trading*, Chapter 3, "The Potential for Cost Savings."

expected since other intervening considerations will, in effect, prevent some economic trading decisions from being made. It has been observed, for example, that local politics have played a significant role in determining which compliance options are considered by a utility. Coal miners (in some cases, with the help of electric utilities) in many key states were able to persuade legislators to pass legislation that ensured the continued use of in-state coal (see Appendix B). While there are substantial cost savings opportunities still available from *inter*utility trading, few utilities have, as noted above, taken advantage of them.

The following example helps make this point. A utility builds a scrubber on one unit at a phase-I-affected plant. This results in that unit being overcontrolled and, as a result, there are excess allowances which can be transferred to other units on the system. Under a command-and-control requirement, these other units may also have to be scrubbed. Now the utility is able to choose the unit or plant with the lowest SO_2 control cost. Another source of savings comes from the fact that the utility has more flexibility in choosing the option for compliance. Thus, the utility can choose from scrubbing, fuel switching, reducing utilization of affected units, repowering a unit or plant, and so on. The result is not only competition among options, but also competition between options. For this reason, scrubber costs and low-sulfur coal prices have been lower than expected.

The other source of savings, is trading between utilities or interutility trading. To date, as the number of trades indicate, this option has not been exercised much by utilities. Of course it could simply be accepted that there will only be one or two dozen trades a year and that the low price reflects their value to electric suppliers. There are indications, however, that utilities are not taking full advantage of the allowance system. As noted, in the ideal case, the market price of allowances should reflect the marginal cost of SO_2 control of all producers. Or stated differently, no utility should be incurring a higher marginal control cost for SO_2 reduction than the going price of allowances. Currently, this is clearly not the case. Again, perfection should not be expected, but the fact that allowances are selling for less than $200 (from recent trades) and some utilities are incurring compliance costs several times[53] this amount, suggests that there is a problem.

The evidence suggests, therefore, that the full benefits of the trading program are not currently being realized. The question then is: Why, at these relatively low allowance prices (compared with incurred SO_2 reduction costs), has there been a low level of utility participation in the market to date?

Reasons for Low Level of Utility Market Activity to Date

Several reasons have been given for the low level of allowance market activity. One possible explanation is that there is an inherent reluctance by utilities to attempt a novel and untried compliance approach, such as trading allowances. It is common in regulatory discussions to refer to utilities as "risk averse" and prone to take least-risk rather that least-cost approaches to problems.[54] While this may or may not be the case, there are several other factors that could contribute to utilities being reluctant to trade allowances and preferring instead what they perceive as a lower-risk strategy. There are at least five of these other factors that could be causing this low level of activity in the allowance market and utility reluctance to participate in it.

First, a number of states, including nearly every key state with substantial phase I compliance requirements, passed legislation that was designed to encourage their utilities to continue to use local coal (see the Appendix B). This was done in several ways, including preapproval provisions for scrubbers, tax credits for in-state coal, automatic passthrough of costs, or mandate of a compliance action. These actions have had the effect of limiting the utility's compliance options or biasing the utility's decision toward self-sufficiency. Interestingly, none of

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[53] This is based on Electric Power Research Institute, *Integrated Analysis of Fuel, Technology and Emission Allowance Markets*, Appendix C, Table C-1

[54] Utilities have argued that due to the uncertainty in the allowance market they are forced to incur these higher control cost in order to bank allowances for their future use. However, there is no practical difference between a purchased allowance and one generated by a utility. A utility can build a reserve of allowances, as some are doing, by purchasing allowances. Building the capability internally should only be done when it is cost-effective to do so (determining this is discussed in the next chapter).

these legislative actions referred to allowance purchases as an option, which would, in many cases, allow the continued use of local coal.[55]

A second possible reason for the lack of market activity was the negative press the first few trades received. News stories in *The New York Times*, *The Wall Street Journal*, Associated Press, and local papers often characterized the trades as the selling or buying of the "right to pollute." While there is an element of truth in this portrayal, it left the impression that the trades were conducted at the expense of the environment. These news stories rarely mentioned, for example, the ten-million-ton annual reduction in SO_2 emissions mandated by Title IV or that the Title I requirements take precedence over the number of allowances held. Utilities, fearing negative publicity, may be reluctant to trade allowances in such an emotionally charged atmosphere.

A third and often-cited reason is the federal EPA rulemaking uncertainty, particularly the allowance tracking system (ATS) and substitution rule change.[56] However, while the substitution rule change may prevent or stop some arrangements, it is difficult to conclude that it had a significant impact on the trading of allowances. Also, EPA has stepped up its efforts to get the ATS operating. At worst, this is only a minor deterrent to trading.

A fourth possibility is the tax treatment of allowances. The Internal Revenue Service (IRS) has decided to use the historical cost basis of the allowances for tax

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[55] As noted earlier, one utility, Illinois Power, that was subject to a state legislative mandate, discontinued construction of a scrubber and deferred its decision to continue it until phase II. Illinois Commerce Commission decisions and recent court decision that overturned the Illinois law are discussed above.

[56] The substitution provision of Title IV allows phase-I-affected utilities to designate other units as substitutes that then become subject to phase I emission requirements. The rule change will likely narrow the definition so that fewer units will qualify, particularly units outside the utility's own system.

purposes.[57] Some argue that this will make utilities reluctant to sell allowances since almost one-third of the revenue from the sale will be taxed. This is likely to have an impact on the sellers of allowances, who will consider the after-tax consequences of their decisions (probably requiring a higher selling price). Buyers, however, are unaffected by the IRS ruling since a tax event only occurs when allowances are sold. To date, the allowance market's problem has not been too few sellers, but too few buyers. Those desiring to purchase allowances have not faced insurmountable difficulties to do so. Therefore, while the IRS ruling will have an impact on selling decisions and will likely affect the price of allowances, it is unlikely that it is a major factor contributing to the low level of market activity.

The fifth and possibly biggest single factor influencing the allowance market is the procedures that public utility commissions and the FERC have chosen to deal with the allowance system. Commission action to date has largely been reactive, responding largely to utility compliance plans. With a few exceptions, they have not actively encouraged their jurisdictional utilities to factor allowances into their decisionmaking process. Recognizing this, the National Association of Regulatory Utility Commissioners (NARUC) in 1993 passed a resolution that encouraged states to consider ". . .tak[ing] prompt action to provide regulatory guidance with regard to ratemaking and accounting treatment of allowance transactions."[58]

A theme that runs throughout the remainder of this report centers on measures state regulators can use to allow the market to develop to its fullest potential and encourage utilities to use the market cost-effectively. This includes commission review and evaluation of compliance plans and the determination of a ratemaking treatment for compliance costs and allowances. The main objective of this analysis is to answer the question: What regulatory treatment is in the best interest of ratepayers?

Go to Chapter 2

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[57] Internal Revenue Service, Revenue Ruling 92-16 and Revenue Procedure 92-91. Tax implications are discussed in Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program,* 95-101.

[58] National Association of Regulatory Utility Commissioners, "Resolution to Encourage States to Enunciate Policies on Treatment of Allowance Transactions," approved at Summer Committee Meetings, San Francisco, California, July 1993.

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CHAPTER 3

DEVELOPING A COMPLIANCE STRATEGY

As discussed, the presence of multiple, interrelated objectives and constraints, and the emergence of a dynamic market environment and a rapidly changing regulatory climate call for a flexible, resilient, and robust approach to compliance planning. Such an approach embodies a *strategy*, rather than a single plan, that can effectively respond to many possible scenarios and contingencies. To develop such a strategy, the utility needs to take several steps. They are: establish compliance objectives, conduct a scoping analysis of scenarios and options, conduct a cost analysis of options, develop a least-cost set of options for a chosen set of scenarios, conduct an analysis of uncertainties and risks (analyze options under different scenarios), develop a set of compliance plans, and finally integrate compliance plans with the overall utility resource plan.

Establishing Compliance Objectives

The utility needs to determine the current emissions of each type of pollutant and compliance requirements set by the U.S. Environmental Protection Agency (EPA). While sulfur dioxide (SO_2) emission caps would dominate the compliance objectives of the utility, limits imposed on other pollutants, which include nitrogen oxides (NO_x) and air toxics also need to be included in setting utility compliance targets. The utility also needs to comply with state and local environmental requirements, which in some states may be more stringent than those set by the EPA. Finally, besides the regulations that apply to criteria pollutants, the utility needs to be cognizant of other environmental requirements, such as carbon dioxide (CO_2) limits, that may be established by future legislation. A utility that limits its planning to meeting compliance requirements that apply to the current set of criteria pollutants, may be faced with making costly adjustments to its compliance plan if future legislation introduces regulations for other pollutants.

The utility also needs to look at its resources, current regulatory policy, and other factors that may impose constraints on its compliance policy.[1] For example, if a utility has a large number of coal plants and is faced with an excess capacity problem, strategies that rely on building additional capacity or reducing existing demand may not be very appealing. Further, if the current public utility commission policy does not allow the utility to retain a portion of the gains from selling allowances, it does not make economic sense for the utility to invest large amounts of funds in overcontrol options. On the other hand, if the commission policy allows a guaranteed recovery of overcontrol investments and expenses, it does make economic sense for the utility to choose overcontrol options, even in the absence of making substantial gains from allowance trading. An evaluation of constraints imposed by the current status of resources and regulatory policy can allow the utility to limit itself to fewer scenarios and options in compliance planning.

The Scoping Analysis of Scenarios and Options

Scenarios

The utility needs to consider a set of possible future events. This set of events represents future occurrences that would influence the utility's decisions. They include, for example, future prices of coal and gas, future allowance prices, future load growth and last but not least, future compliance requirements (for example, the possibility of future CO_2 legislation). After considering a broad enough event set, the utility may want to rank the events in terms of their probabilities of occurrence and impact on the utility's costs and revenues.[2] Such ranking may help the utility focus on the more important events and pay less attention to events that may be less likely to occur.

By its very nature, the scoping of scenarios would have a high degree of subjectivity.

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[1] The influence of various factors on compliance planning has been discussed in more detail in Chapter 1. Also, the effect of regulatory treatment on compliance planning appears later in the report.

[2] There is interdependence of probabilities among events. A small probability of high load growth, for example, may imply a small probability of high compliance requirements.

Some events may be more amenable to quantitative (but still subjective) evaluation than others. For example, it may be easier to assign probabilities to the occurrence of a certain load growth and a certain allowance price than to assign a probability to the occurrence and the timing of future CO_2 legislation. In the final analysis, the utility planner needs to develop a set of future projected events with assigned probabilities such that each chosen event is expected to have a nontrivial effect on the utility's future yet ensure that no important event has been excluded.

Options

The utility needs to establish a menu of compliance options. Initially, the menu should be exhaustive and include all options that are available to the utility. In the next stage of the scoping analysis, a qualitative ranking of options, similar to that of scenarios, can be done for the options. Options may be ranked according to such criteria as cost, availability, effectiveness for pollution control, and risks.

The results of the screening of scenarios would also help the utility to rank options. The final product of such an analysis would be a matrix that ranks the various options according to a number of attributes. The matrix should convey to the utility planner which options are likely to be most effective and which ones can be dropped from further consideration. Some utility planners may prefer to attach a weight to each attribute to arrive at a final score for each option. The problem with this method is that the subjective and qualitative nature of the analysis can prematurely preclude options which otherwise would have been promising. It may be better to use a multiattribute criteria and reject those options that score low on most attributes. At this early stage, it is better to err on the side of comprehensiveness and include as many options as possible rather than drop apparently unimportant options which may turn out to be important upon further analysis.

Cost Analysis of Compliance Options

After a preliminary, qualitative scoping of options, the most promising options can be chosen for more rigorous cost analysis. The analysis involves two steps: the calculation of costs for each option and the comparison of options according to calculated costs. It needs to be recognized that a set of cost calculations needs to be performed for each given combination of scenarios. In other words, the calculated costs are functions of the assumed scenarios.

Calculation of Costs

The calculation of costs can be performed using several methods. The method commonly used for estimating compliance costs is levelization. In this method, a series of equal annual payments, known as the levelized cost, is estimated such that the total present worth is equal to the present worth of the actual stream of projected payments. The levelized cost is given by:

$$L = \frac{(PV)\,(i)\,(1+i)^n}{(1+i)^n - 1} \qquad \textbf{(3-1)}$$

where PV = present value of the stream of payments

i = discount rate

n = number of years compliance option is in effect

The present value of the stream of payments is given by

$$PV = \frac{\tau_1}{1+i} + \frac{\tau_2}{(1+i)^2} + . \; . \; . + \frac{\tau_n}{(1+i)^n} = \sum_{k=1}^{n} \frac{\tau_k}{(1+i)^k} \qquad \textbf{(3-2)}$$

where τ_k = payment in year k

Since data for annual costs and pollution reduction are generally available, this method allows a comparison of costs per unit reduction of different compliance costs. This can be defined as the average cost of compliance for each option and can be calculated as:

$$C_j = \frac{L_j}{R_j} \qquad \textbf{(3-3)}$$

where C_j: pollution control costs of option j in dollars per ton

L_j: levelized cost of option j in dollars

R_j: expected annual pollution reduction of option j in tons

One important parameter in calculating levelized average costs of compliance is the planning horizon. Depending on the planning horizon chosen, the calculated cost values will be different. Also, the choice of the planning horizon has important implications for how the calculated costs are evaluated for making compliance decisions.

<u>Levelized Life-Cycle Costs</u>

A device or piece of equipment installed at a power plant to control pollutants may have an economic or useful life that may be greater or less than the plant itself. If it is greater than the plant itself, its useful life is limited to that of the plant unless it can be transferred to another plant. Usually, however, technological development may render the equipment obsolete and incapable of being used in another plant. If the equipment life is less than the remaining life of the plant, then clearly the former is to be taken as the useful life of the equipment.

Once the useful life of the equipment has been established, the next step is to find the contribution of different cost components. There are two basic components of cost: capital and operating. Capital costs include construction expenditures and any applicable interest on funds used to finance construction. Operating costs include fuel, maintenance, and other expenditures incurred to operate a facility once it is constructed and is in service. Both capital and operating costs have components which may be subject to different regulatory and accounting treatments. Such treatment, in turn, determines the effect of each component of cost on the levelized compliance cost.

As is well known, there are two basic regulatory treatments of the capital cost. Construction expenditures may be included in the rate base and allowed to earn a return as construction work in progress (CWIP). Alternatively, a public utility commission may not allow a return on CWIP until the facility is completed and is in service. In this case, the investments needed to finance construction of the facility earn interest, known as "allowance for funds used during construction" (AFUDC), over the construction period. Once the facility is completed, and deemed prudent, the cumulative AFUDC, along with the total investment in the facility, becomes part of the rate base.

If CWIP is included in the rate base, the capital cost to be borne by ratepayers has three components. The first is the annual return earned on the CWIP by the utility over the construction period. The second is the annual return earned on the total investment in the completed facility over its operating life. Finally, the third component is the annual depreciation charge on the facility over its operating life, allowing the utility to recover the investment. The first and second components constitute the carrying charges on the investment. These are charges the utility needs to recover to meet its financial obligations on the investment in the facility.

If CWIP is excluded from rate base and AFUDC is added to the rate base, the capital cost to be borne by ratepayers has two components. The first is the annual return earned on the rate base (which includes AFUDC) over the operating life of the facility. The second is the annual depreciation charge on the investment in the facility (which includes AFUDC). In other words, the AFUDC treatment results in a greater carrying charge over a smaller period (as it excludes the construction period).

Clearly, the two treatments (CWIP and AFUDC) differ significantly both in the timing and the amounts of recovery allowed to the utility. Also, a utility may be allowed a partial CWIP treatment, which would result in a cost recovery that would be different from that under either a pure CWIP or pure AFUDC treatment.

The second basic component of costs to be borne by ratepayers is the operating costs. Unlike capital costs, the calculation of the contribution of operating costs to the present value of the revenue requirement (PVRR) and the levelized cost is relatively straightforward. Public utility commissions generally allow operating costs as a passthrough to customer rates. Therefore, the discounted value of annual operating costs is the contribution to PVRR, which after levelization becomes the levelized cost.[3]

Life-cycle levelized costs provide an adequate yardstick for comparing the long-term costs and benefits of pollution control technologies and options. However, life-cycle levelized costs represent a simplified metric in the compliance planning realm. Analysts must also address the operating life and year-to-year charges associated with compliance options when performing more detailed analysis.

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[3] An important factor to consider when conducting multiyear planning (a compliance or other resource plan) is the choice of the discount rate. Since the resource choice may depend on the discount rate chosen, a great deal of effort is often put into its determination. This important and complex task is not covered in this report.

Short-Term Levelized Costs

One alternative to life-cycle levelized costs is short-term levelized costs. In this method, a shorter period (approximately ten years) is chosen rather than the typical life cycle (approximately thirty years) to calculate the levelized cost. The rest of the calculations are similar to those for life cycle levelized costs.

This method has the merit of tending to mitigate the effects of the uncertainty of projecting future costs over a relatively long time period. Another feature of this cost index is that it tends to magnify the effect of the initial, capital costs relative to the operating costs. The use of this index allows the utility planner to more clearly see the short-term effects of an investment. The disadvantage is that an undue reliance on short-term costs may contribute to a myopic compliance plan. The compliance plan needs to achieve a balance between the short term and long term and make a judicious use of both cost indices.

Ranking Options According to Costs

The next step in the analysis is comparing costs of alternative options. The cost index to be used in the comparison may be life-cycle or short-term costs. Also, the comparison applies only to one set of assumed scenarios and may change when the scenarios are changed.

The comparison of costs can best be illustrated using a small number of options.[4] Assume that the utility has three mutually exclusive (or substitutive[5]) options,

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[4] These options were chosen for illustrative purposes and are not from any actual utility compliance plan. As will be discussed later in this chapter, actual compliance plans should be a great deal more complex. The basic procedure, however, of choosing compliance options will essentially be the same as these simplified examples.

[5] The term "substitutive" is used here to refer to options that are mutually exclusive. This should not be confused with "substitution units" under Title IV.

A, B, and C, to employ for emissions reduction at one of its affected units. Table 3-1 shows the annual costs and SO_2 reductions of each option. Also assume that the allowance price is $300 a ton and the plant emits 20,000 tons of SO_2 in excess of the emission cap.

To decide which of the options should be chosen, one can use the principle that the cost per ton of the chosen option should not exceed the allowance price. Otherwise, the utility would be better off buying allowances rather than employing the option. It is important to note that it is the *incremental* or *marginal cost* rather than the average cost of an option that should be used to make the comparison with the allowance price.

The average cost of an option can be defined as the ratio of total costs incurred and the total reduction of SO_2 achieved by using the option. The incremental cost, on the other hand, is dependent on the next cheapest option and can be defined as the ratio of the additional costs incurred and the additional reduction of SO_2 achieved by the current option. There are relationships between total, average, and incremental costs. Such relationships and the use of incremental costs to develop a least-cost set of options are illustrated in the following examples.

TABLE 3-1

AVERAGE AND INCREMENTAL COSTS OF SUBSTITUTIVE COMPLIANCE OPTIONS

Option	Total Cost (thousands of dollars)	SO_2 Reduction (tons)	Average Cost ($/ton)	Incremental Cost ($/ton)
A	2,000	10,000	200	200
B	4,000	15,000	267	400
C	5,500	18,000	306	500

Source: Authors' construct.

Substitutive Options

Assume that all three of the sample options are substitutes, that is, only one option can be used at a time. This may be the case, for example, if A represents fuel switching, B represents cofiring with gas, and C represents repowering at the same plant. Substitutes may be mutually exclusive in a physical sense (repowering may not work with a certain grade of low-sulfur coal, for example) or regarded as stand-alone alternatives (cofiring and fuel switching may work together but still may be considered substitutes for the same plant).

When options are substitutes, the incremental cost is found by arranging options in order of increasing SO_2 reductions and dividing the difference in costs by the difference in reductions for successive options. Table 3-1 shows the calculations. As Table 3-1 illustrates, starting at option B, incremental costs are much higher than average costs. If average costs were used as the basis of choosing options, then either A or B could be chosen because each has an average cost lower than the allowance price. C has an average cost higher than the allowance price and would be rejected.

However, comparison of incremental costs with the allowance price shows that only option A should be chosen. Table 3-2 shows the calculations to demonstrate that A represents the least-cost choice.

One may intuitively think that A is the least-cost choice because it has the lowest average cost. However, that may be misleading. As stated earlier, the least-cost option set will contain every option with an incremental cost lower than the allowance price. If the option set consists of a single option, the option with the incremental cost which is closest to, but does not exceed the allowance price, will be the least-cost choice. In fact, the single option with the lowest average cost may not represent the least-cost choice in many cases.

To verify this observation, assume that the allowance price is \$450 a ton instead of \$300 a ton. As Table 3-3 shows, option B becomes the least-cost choice in this case. This is true in spite of the fact that option B does not have either the lowest average cost

TABLE 3-2

NET COST OF SUBSTITUTIVE COMPLIANCE OPTIONS: CASE 1

Option	Total Cost (thousands of dollars)	SO_2 Reduction (tons)	Allowances Purchased ($/ton)	Allowance Cost (thousands of dollars)	Net Cost (thousands of dollars)
A	2,000	10,000	10,000	3,000	5,000
B	4,000	15,000	5,000	1,500	5,500
C	5,500	18,000	2,000	600	6,100

Source: Authors' construct.

Notes: Allowance price = $300 per ton.
Excess SO_2 emission = 20,000 tons.

TABLE 3-3

NET COST OF SUBSTITUTIVE COMPLIANCE OPTIONS: CASE 2

Option	Total Cost (thousands of dollars)	SO_2 Reduction (tons)	Allowances Purchased ($/ton)	Allowance Cost (thousands of dollars)	Net Cost (thousands of dollars)
A	2,000	10,000	10,000	4,500	6,500
B	4,000	15,000	5,000	2,250	6,250
C	5,500	18,000	2,000	900	6,400

Source: Authors' construct.

Notes: Allowance price = $450 per ton.
Excess SO_2 emission = 20,000 tons.

or the lowest incremental cost. Table 3-3 shows that option B has the incremental cost that is closest to but less than the allowance price of $450 a ton.

Additive or Complementary Options

Instead of being substitutes, options can be additive or complementary. For example, each option may now represent fuel switching at each of three different units. When options are additive, the incremental cost and the average cost are the same for a given option. This holds because for each option the additional cost is the same as the total cost of the option and the additional reduction is the same as the total reduction.

As the incremental cost and the average cost become equal for each of an additive set of options, the least-cost choice also changes from what it is for a substitutive set of options. To illustrate this, assume that the total excess emissions in the three plants are 20,000 tons and the allowance price is $300 a ton. Tables 3-4, 3-5, and 3-6 show the calculations. From Table 3-4, the incremental cost of B is $267 a ton and of C is $306 a ton, which is the same as the average costs of the two options. Table 3-5 shows that the least-cost choice is the combination of options A and B. Because B is

TABLE 3-4

AVERAGE AND INCREMENTAL COSTS OF ADDITIVE OPTIONS

Option	Total Cost (thousands of dollars)	SO_2 Reduction (tons)	Average Cost ($/ton)	Incremental Cost ($/ton)
A	2,000	10,000	200	200
B	4,000	15,000	267	267
C	5,500	18,000	306	306

Source: Authors' construct.

TABLE 3-5

NET COST OF ADDITIVE OPTIONS:
CASE 1

Option	Total Cost (thousands of dollars)	SO_2 Reduction (tons)	Allowances[1] Purchased/ Sold ($/ton)	Allowance[2] Cost/Credit (thousands of dollars)	Net Cost (thousands of dollars)
A	2,000	10,000	10,000	3,000	5,000
A, B	6,000	25,000	(5,000)	(1,500)	4,500
A, B, C	11,500	43,000	(23,000)	(6,900)	4,600

Source: Authors' construct.

General Notes: Allowance price = $300 per ton.
Excess SO_2 emission = 20,000 tons.

[1] Quantity in parentheses indicates allowances sold.
[2] Quantity in parentheses indicates credit for allowances.

additive to A, the least-cost choice includes every option, A and B in this case, with incremental cost less than the allowance price (Table 3-4). For an allowance price of $450 a ton, and using similar analysis, Table 3-6 shows that the least-cost set of options is (A,B,C). These results are clearly distinct from the results obtained for the case of substitute options.

TABLE 3-6

NET COST OF ADDITIVE OPTIONS:
CASE 2

Option	Total Cost (thousands of dollars)	SO_2 Reduction (tons)	Allowances[1] Purchased/ Sold ($/ton)	Allowance[2] Cost/Credit (thousands of dollars)	Net Cost (thousands of dollars)
A	2,000	10,000	10,000	4,500	6,500
A, B	6,000	25,000	(5,000)	(2,250)	3,750
A, B, C	11,500	43,000	(23,000)	(10,350)	1,150

Source: Authors' construct.

General Notes: Allowance price = $450 per ton.
Excess SO_2 emission = 20,000 tons.

[1] Quantity in parentheses indicates allowances sold.
[2] Quantity in parentheses indicates credit for allowances.

Codependent Options

Besides being substitutive or additive, options can be codependent. Codependence may be defined as a relationship between options such that if one option is chosen, the other option must be chosen (implying mutual inclusiveness). For example, if fuel switching of one unit of a two-unit generating station is chosen, fuel switching may have to be chosen for the other unit because the station has a single coal handling facility. However, it may be possible to scrub one unit without scrubbing the other. Therefore, fuel switching at the two units represents a codependent option and scrubbing represents an independent (and additive) option. When options are codependent, they should be collectively treated as a single option.

Developing a Least-Cost Set of Options

The following important observations are derived from the above examples:

1. Small differences in average costs may correspond to much larger differences in incremental costs.
2. Choosing all options with incremental costs lower than the allowance price *minimizes* the *total* cost of compliance.

The following additional observations may be derived from the above observations:

3. A mathematical or engineering model that attempts to minimize the total or average cost of a compliance plan would yield the same result as the method of successively using incremental costs.[6]
4. There may be many options or plans whose average cost[7] is lower than the allowance price. This means that the utility is better off selecting any one of such options or plans than meeting its entire compliance requirement by buying allowances. But none of these options or plans are necessarily least cost. Only method 2 or method 3 listed above yields the minimum cost plan.
5. It is important to avoid the confusion that may be caused by statement 4. Statement 4 does not mean that minimizing (using a mathematical search technique) the average cost of a set of options does not yield the least-cost plan (because it does as stated in 3). It means that simply comparing the average cost (rather than the incremental cost) of one option to another, or an entire plan to another plan (unless the set of plans is exhaustive), or of a plan to the allowance price is not useful in arriving at the least-cost

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[6] The calculations shown in Table 3-2 represent how an engineering model would attempt to find the combination of options with the minimum total or average cost. Table 3-1 shows that the method of successively using incremental costs also produces the minimum-cost set of options.

[7] The average cost of a plan is the total cost of all options in the plan divided by the total reductions achieved.

plan.

The findings and observations made in preceding sections can be used to establish a procedure to find the least-cost set of options. The steps in the procedure are:

1. Arrange the options in order of increasing average costs
2. Treat a set of codependent options within the list as a single option.
3. Within every set of substitutive options, compare the order of reductions. If the order of reductions does not follow the order of average costs (an increasing order from step 1), drop the option that deviates from the order. The deviating option may be termed a nondominant option.
4. Calculate the incremental cost of each option. For an option that is additive to all preceding options in the modified list in step 3, the average cost of an option is the incremental cost. For an option that is substitutive to a preceding option (not necessarily immediately preceding), the incremental cost is the ratio of the additional cost incurred and the additional reductions achieved relative to the preceding substitutive option.
5. Arrange options in increasing order of incremental costs.
6. Select every option with incremental cost less than the allowance price. The selected set represents the least-cost choice of options.
7. If the selected set contains subsets of substitutive options, retain only the option with the highest cost (and higher emissions reduction) and drop the other, lower cost options within each subset.

Table 3-7 lists a set of options for a system with three plants, A, B and C. Plant A has two units, A_1 and A_2, and B and C are single unit plants, and option 3 is treated as a codependent option for both units of A. The list has been arranged in order of increasing average cost. Table 3-7 indicates that option sets (1,5,7), (2,3,6) and (3,4,8) are substitutive. Comparing reductions for options within each set shows that option 4 in the second set has a smaller reduction (12,000 tons) and a higher average cost ($241 a

TABLE 3-7

AVERAGE COSTS OF OPTIONS FOR A THREE-PLANT SYSTEM

Option Number	Action	Total Cost (thousands of dollars)	SO_2 Reduction (tons)	Average Cost ($/ton)
1	Switch B	3,375	15,000	225
2	Repower A_1	2,300	10,000	230
3	Switch A_1 and A_2	4,012	17,000	236
4	Repower A_2	2,892	12,000	241
5	Repower B	4,940	20,000	247
6	Scrub A_1	9,555	21,000	455
7	Scrub B	12,636	27,000	468
8	Scrub A_2	6,507	13,500	482

Source: Authors' construct.

ton) than option 3 (17,000 tons and $236 a ton). Therefore, according to the rule in step 3, option 4 can be dropped from further consideration.

Assume that the allowance price is $250 a ton and total excess emission from the three plants is 40,000 tons. Table 3-8 lists the options in order of increasing incremental costs. Only options 1, 2, and 3 have lower incremental costs than the allowance price. Therefore, (1,2,3) represents the least-cost choice of options.

It is helpful to depict incremental costs and reductions in a bar diagram, as shown in Figure 3-1. The figure also shows the allowance price as a dotted horizontal line and the excess emission as a vertical dotted line. All options with vertical heights (representing incremental costs) lower than the allowance price constitute the least-cost option set. If the horizontal line representing the allowance price is moved up,

TABLE 3-8

INCREMENTAL COSTS OF OPTIONS FOR A THREE-PLANT SYSTEM

Option Number	Preceding Sustitutive Option	Action	Total Cost (thousands of dollars)	SO_2 Reduction (tons)	Additional Cost (thousands of dollars)	Additional Reduction (tons)	Incremental Cost ($/ton)
1	None	Switch B	3,375	15,000	3,375	15,000	225
2	None	Repower A_1	2,300	10,000	2,300	10,000	230
3	2	Switch A_1 and A_2	4,012	17,000	1,712	7,000	244
5	1	Repower B	4,940	20,000	1,565	5,000	313
6	2	Scrub A_1	9,555	21,000	5,543	4,000	1,386
7	5	Scrub B	12,636	27,000	7,696	7,000	1,099
8	3	Scrub A_2	6,507	13,500	2,495	3,500	713

Source: Authors' construct.

Fig. 3-1. Incremental cost and SO_2 reductions of control options.

additional options may become members of the least-cost option set. If the line is moved down, options may drop out of the set. For example, if the allowance price is raised to $350 a ton, option 5 becomes a member of the least-cost option set.

A "stair-step" compliance curve, as depicted in Figure 3-1, can be used to clearly represent the sensitivity of the least-cost option set to the allowance price for a given set of options with specified incremental costs. Such a curve may be very helpful to utility planners to test the viability of alternative plans for a wide range of expected allowance prices.

The compliance curve is useful in illustrating other important characteristics of compliance plans. The area of a given segment of the compliance curve represents the total cost of all options included in the segment. For example, the shaded area in Figure 3-1 represents the total cost of options 1 and 3. It should be pointed out that since options 2 and 3 are substitutive, the final option set includes option 3 but does not include option 2. To clarify this point, one needs to recall that the total cost of option 3 is the sum of the total cost of option 2 and the incremental cost of option 3. Therefore, the shaded area includes the contribution of only options 1 and 3 even though option 2 appears on the curve.

Another interesting, and important, observation from Figure 3-1 is that for a given set of options with specified incremental costs, the *composition* of the optimal compliance plan depends only on the allowance price and does not depend on the excess emission above the compliance cap. The excess emission does affect the *net cost* of compliance, however. This is true because the need to purchase allowances or the availability of excess allowances for sale depends on the level of shortfall or of excess emissions above the compliance cap. Therefore, the net cost of compliance contains the additional cost of purchasing allowances or the revenue from selling allowances.

Treating Systemwide Options

The preceding sections present a useful way to rank compliance options and develop an optimal compliance plan. The options included in the illustrative exercises are plant- or unit-specific. The exercises, however, did not include systemwide options, such as redispatching[8] and demand-side management (DSM), which depend and in turn influence system operations. Redispatching, because it reorders the sequence in which units are brought on line, modifies the production cost, the level of emissions and the pollution control cost of each option. DSM options, by modifying the peak demand and the total energy demand, also influence the values of the same operational variables.

Emissions Dispatch

Traditionally, the dispatching of units in a power-generation system is ordered to minimize generation costs. The unit with the least variable operating cost, which includes fuel and maintenance costs, is dispatched first, followed by units with successively higher variable operating costs. This dispatching protocol is known as economic dispatch. Variable costs used to determine the economic dispatch order also include direct pollution control costs incurred to comply with existing (pre-CAAA) environmental regulations. Conventional economic dispatch, however, does not include a consideration of other, indirect costs imposed on the environment and society by the operation of electric power plants. Over the last fifteen years, a regulatory regime has emerged that increasingly requires consideration of such costs in both planning and operation of a power system. In planning, consideration of such costs causes a preference for generation technologies and resource mixes that tend to minimize environmental pollution and other adverse socioeconomic impacts. In system operation, the same consideration may lead to a modification of the unit dispatch order that not only minimizes direct operating costs but also attempts to minimize the environmental or societal costs of power generation.

[8] For the remainder of the report, redispatching is used instead of emissions dispatching to represent modification of the load dispatch order according to some emission-based criteria.

The central, and well-known, economic notions that would drive the reordering of unit dispatch are externality and opportunity costs. An externality may be defined as a cost for which an economic agent is not compensated or a benefit for which an economic agent does not pay. An opportunity cost may be defined as the foregone economic benefit as a result of the current use of inputs, skills or resources owned by an economic agent.

The pollution caused by power production may be considered an externality because it imposes a cost in the form of adverse health, ecological and economic consequences for which the producer or the consumers of power do not pay. Environmental regulation, either of the traditional "command-and-control" variety, or of a more market-oriented form, such as the CAAA, attempts to internalize such externalities, by imposing additional costs on power producers that depend on the level of emission of specific pollutants. Under command-and-control environmental regulation, the additional cost may either be the cost of installing and operating pollution control devices to reduce the emissions to a mandated level, or a cost penalty imposed on each unit of emissions.[9] Under the CAAA, the cost of compliance for one pollutant, SO_2, is intended to be driven by a market of tradeable emission allowances while other pollutant emissions are subject to mandated caps.[10]

An investor-owned utility or another power producer needs to consider the externality costs, internalized by the CAAA and other applicable federal, state, and local regulations, in its dispatch decisions. The effect of different types of environmental regulations, however, is quite different on the economics of dispatching.

One simple way to incorporate the externality costs of pollutant emissions in system dispatch is to minimize emissions. This approach is known as least emissions dispatch. Such an approach would require dispatching the unit with least emissions first, followed by units with

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[9] A cost penalty per unit of emission, known as an externality adder, has been used by several commissions. The intended policy goal, however, is to influence the future resource mix rather than to reduce environmental costs of operating existing units.

[10] Under the CAAA, NO_x is subject to unit-specific emission caps according to rules issued by the EPA. Other criteria pollutants are to be controlled according to future rules to be issued by the EPA.

successively higher emissions. While this may minimize the costs of pollution, it may increase other operating costs. The less polluting units may also have higher operating costs and if they are dispatched first, the operating cost is likely to increase relative to conventional economic dispatch.

The rational way to minimize operating costs, is to include both the operating costs and environmental costs (quantified according to some economic standard) in determining the unit dispatch order. This approach is known as full cost dispatch. The dispatch order is designed to minimize the total cost (including the environmental cost) of operating units in a generation system. The economics of dispatching, under this approach, depend on the form of environmental regulation.

If an environmental regulation imposes a penalty per unit emission of a pollutant, the effect on dispatch order is relatively straightforward to estimate. It involves adding the cost penalty for the actual level of emissions to the operating cost of units. The resulting cost becomes the basis for determining the dispatch order and is likely to be different from traditional economic dispatch order.[11] Also, the economic impact on the dispatch order may be different based on whether the cost penalty represents an out-of-pocket cost (as in an emissions tax) or a policy artifact (as in the use of externality adders) intended to realize a certain mix of resources (or certain mode of system operation). In the first case, the utility would trade off the total penalty against the additional operating costs imposed by changes in the dispatch order. In the second case, the utility would choose a resource mix (the intended goal of externality adders currently in use) or, for an existing system, a dispatch order that minimizes the externality-adjusted system cost.

For pollutants with mandated emission caps (with possible cost penalties per unit emission above the cap), the effect on the dispatch order may be more complicated to estimate. The affected unit can be moved further down the dispatch order to reduce pollutant emissions to a certain level. The level can be set such that the incremental operating costs imposed by

[11] Redispatching, in response to the imposition of externality adders, is yet to become an environmental control option. It may become such an option if the externality adder also applies to existing units. Also, consideration of the redispatching option may influence the choice of future resource mixes of utilities.

redispatching are lower than the incremental cost of achieving the same reduction using alternative control options. Any residual compliance requirement needs to be met by installing pollution control devices.[12] For a system with multiple affected units, an approach similar to the stair-step compliance curve for unit-specific options can be used. Under this treatment, alternative redispatching options are substitutive and the redispatching option with the incremental cost closest to but lower than the lowest cost control option is chosen.[13]

For pollutants with marketable permits or allowances, such as SO_2, the incorporation of pollution control costs into dispatch decisions is similar to that for pollutants with per unit cost penalties. The appropriate cost adder, however, is the market price of allowances. Unlike the cost penalty per unit of pollution, the price of allowances is not necessarily either a direct out-of-pocket cost or a policy artifact. The allowance price is not necessarily a direct cost because utilities will receive a specific number of allowances as endowments from the EPA. It is not simply a policy artifact because the utility may incur actual costs if it needs allowances beyond those received from the EPA and also because it can earn revenues by selling excess allowances. The appropriate economic notion that applies to the allowance price as an adder to unit operating cost is opportunity cost. Regardless of how many allowances a utility receives as endowment and how many it needs to meet compliance requirements, each allowance is worth a certain price in the market. If the utility buys allowances, it needs to pay this price. If it is better off selling allowances, each allowance will command this price. Therefore, a full cost dispatch approach designed to meet compliance requirements for SO_2 under CAAA would incorporate the allowance price as the appropriate adder to variable operating costs for determining the dispatch order.

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[12] Note that mandated caps have not yet been used to offset dispatch order. Rather, the use of specified control technologies is required to achieve the desired reduction.

[13] Current environmental regulation (including provisions for non-SO_2 criteria pollutants in the CAAA) does not warrant this treatment because the cap is on a unit rather than the system. Also, unlike the treatment of SO_2 in the CAAA, credits from reduced emission from one unit cannot be used at another unit. The suggested approach may, however, become useable, if future regulation either makes emission caps systemwide or allows transferability of emission credits (with or without a nationwide allowance market) within the units of a system.

Once the appropriate control cost (in dollars per ton) is chosen, emissions dispatching can be treated the same way in a stair-step compliance curve as the other control options. One complication, however, arises in the calculation of direct control costs as the dispatch order is changed. The change in dispatch order changes both the level of emissions and the cost of using control options[14] (other than redispatching). Therefore, the average and incremental costs of each control option are also changed. To address this problem, one can use a mathematical search technique in which all control costs (including that of redispatching) are recalculated at each step of comparing incremental costs of options.

DSM Options

DSM options affect emissions of SO_2 and other pollutants in two different ways. With effective DSM, there is need for less generation and therefore often fewer emissions. Also, DSM may reduce the need for future capacity which may further reduce emissions. However, the opposite effect on emissions can occur if the reduced demand leads to reduced use of relatively cleaner existing units or extended use of older, dirtier units as substitutes for new, cleaner units. Therefore, the effect of DSM on utilization of existing units and the additions of new capacity needs to be carefully analyzed to find the effect on emissions of SO_2 and other pollutants.

[14] This happens as the contribution of operating costs of control options to the levelized cost changes while the capital cost and related carrying charges remain unchanged.

Need for Systemwide and Dynamic Analysis

The approach presented in the preceding sections for developing a compliance plan may not sufficiently capture the effect of systemwide options, such as redispatching and DSM. To treat systemwide options, the general approach represented by a stair-step compliance curve, needs to be augmented to incorporate the effect of redispatching and DSM options. One way to accomplish this is to specify reduction levels, total control costs, and average and incremental control costs as functions of dispatch order and system demand. This may entail constructing many compliance curves for various combinations of dispatch order and system demand.

The complexity of performing such analyses may require the use of sophisticated engineering models for production costing and load forecasting that can adequately simulate the effects of redispatching and DSM options. It should be noted that calculation of reduction levels and control costs also require the use of engineering models. However, once reduction levels and control costs have been obtained, the ranking of options and the construction of the compliance curve can be done separately from simulations of engineering models.

The two tasks are no longer separable, however, once the complexity of treating different dispatch orders and DSM options are introduced into the analysis. Such complexity requires that an integrated engineering model be used both to derive compliance costs for individual options and also to simulate the variation of these costs as functions of system dispatch order and system demand.

Incorporating Dynamic Effects

The analysis so far has been essentially static--it uses levelized values of costs to compare options. Such analysis does not capture the dynamic character of the planning process. The use of levelized values may make two options, or plans, appear to be equivalent even when their timing differences may be important to the utility.

For example, it is possible for two options, such as scrub unit x_1 in year y_1, and switch unit x_2 in year y_2 to have the same levelized average cost. Since the two options are additive, both would have the same incremental cost and both can be chosen if the incremental cost is lower than the allowance price. However, scrubbing unit x_1 may allow the utility less flexibility than switching unit x_2 particularly if y_1 is earlier than y_2. The first option locks the utility into a capital-intensive option beginning in year y_1 and allows no room to respond to future changes in market conditions. With the second option, the utility can wait until year y_2 before making a significant capital investment.

There are other dynamic effects that cannot be captured by the comparative static method using levelized costs. Two plans may have equal levelized costs. Yet, one plan may have a higher share of the costs occurring in earlier years. Such a plan may not be preferred over the other plan because the utility may be concerned with recovery of its capital expenditures.

Therefore, while comparative statics using levelized costs represent one way to rank compliance options and plans, other methods and analytical tools need to be used to address the dynamic character of the planning process.[15]

Detailed simulations of yearly and short-term costs, and qualitative rankings of flexibility may be supplemented to the static analysis to make the planning process more robust with respect to both short-term and long-term consequences. To develop a strategy that is reasonably comprehensive in incorporating the dynamic features of the planning process, however, requires a more generalized treatment. Such a treatment calls for a general planning framework that incorporates the variability of all planning parameters. Such a framework must identify the presence, and the consequences, of uncertainties and risks associated with implementing a compliance plan.

[15] The first example above shows that comparative statics may not account for long-term flexibility of a plan. The second example shows that this method may not capture important short-term consequences of a plan.

Treating Uncertainties and Risks in Compliance Planning

Utility planners today invariably recognize the importance of treating uncertainties and risks in any planning effort. The need to account for uncertainties became pertinent following the failure of many planning parameters to meet forecasts in the 1970's and early 1980's. As previously discussed, the requirements of the Clean Air Act Amendments of 1990 (CAAA) adds to the pre-CAAA list of planning parameters. The expansion of the list of parameters also entails an expansion in the range of uncertainties and risks that need to be treated in the utility planning process.

It is important to clarify the relationship between uncertainties and risks. An uncertainty represents the variability of a parameter while a risk represents the potential adverse consequences of such variability. For example, the prices of coal and gas are subject to uncertainties. A utility that relies more heavily on coal may be faced with higher than expected operating costs, if coal prices rise more rapidly than gas prices in the future. This probable adverse outcome of the fuel price uncertainty (higher than expected operating costs) can be characterized as a risk.

It may be useful to classify uncertainties, as well as risks, according to measurability and controllability. A measurable uncertainty is amenable to mathematical treatment; it has a known probability distribution. For example, it is well known that the probability of obtaining a head in an unbiased tossing of a coin is 0.50 although the exact outcome is uncertain. The tossing of a coin therefore represents a measurable uncertainty. An unmeasurable uncertainty, on the other hand, may not have such a known probability distribution. For example, it would have been highly difficult or impossible to estimate the probability of the occurrence of the Middle East oil embargo a few years prior to the actual occurrence of the event. While advances in statistical techniques may make particular uncertainties more measurable than others, there exists the possibility that some uncertainties may remain inherently unmeasurable.

Risks may also be characterized as controllable and uncontrollable. Controllable risks are those whose magnitudes can be influenced by actions of the decisionmaker. For example, the utility may attempt to improve its construction management procedure and as a result, reduce the magnitude of the construction risk. On the other hand, there may be little the utility can do to influence future fuel prices and attendant risks.

It may be intuitively apparent that unmeasurable risks may be generally less controllable than measurable risks. However, controllability may not have a clear correspondence with measurability. A risk which is more measurable may also be less controllable than another, less measurable risk. The simplest example is the coin toss, which has a well-known probability distribution, yet whose outcome cannot be influenced by any human action. As another example, the utility may come up with a statistical forecast of future demand yet cannot expect to influence the related uncertainty. The utility may be able to reduce the final magnitude of the demand by instituting DSM programs (whose effectiveness is also subject to uncertainties of a different kind) but still cannot control the variability of the demand in any predictable way. A utility may also be able to reduce its operating risk by improving plant maintenance procedures while one component of this risk, fuel prices, is outside utility control.[16]

Finally, the classification of risks is not precise. Most risks are not pure; they may not fit clearly into any category based on either measurability or controllability. In other words, risk categories may overlap. Also, a risk may have components that have different degrees of measurability and controllability. The risk of a future regulatory disallowance depends on future demand, which the utility cannot control, and also on the type of capital investments to be chosen, which the utility can control.

The classification of risks may serve as a useful analytical tool in utility compliance planning. To incorporate the effects of uncertainties and risks, the utility planner can mathematically analyze measurable risks, qualitatively evaluate unmeasurable risks and limit the decisionmaking process to controllable risks.

The presence of uncertainties and risks mean that a unique "least-cost" plan cannot be defined. A plan which achieves the lowest cost under some circumstances may perform poorly under others.[17] There is a general recognition among utility analysts that a plan should be

[16] This shows that a given type of risk may have components each of which may have a different level of controllability.

[17] Eric Hirst, *Regulatory Responsibility for Integrated Resource Planning* (Oak Ridge, TN: Oak Ridge National Laboratory, 1988).

"robust" enough to perform reasonably well under many possible scenarios and circumstances although it may not be the best plan under any one of them.[18]

Analyzing Risks

As a result of the growing need for risk-responsive planning in many industries, a number of analytical tools have emerged in the last four decades that can be used to represent and evaluate uncertainties and risks. These tools have mostly been generated by the growing field of operations research and have found applications in such diverse fields as combat planning and assembly-line manufacturing. Some of these tools have been used in the utility industry to develop generation plans.

Optimization Techniques

Mathematical optimization methods allow the minimization or maximization of a chosen objective function or performance index under a set of known constraints. For example, an optimization technique can attempt to minimize the total levelized cost (the objective function) of compliance subject to a minimum system reliability (the constraint). The more well-known optimization methods are linear programming, nonlinear programming, and dynamic programming. Although these methods were initially designed to optimize deterministic problems (problems with certain outcomes), they can be adapted for use with probabilistic problems (problems with uncertain outcomes and known probability distributions). The adaptation may sometimes involve simply redefining the objective function as a statistical expectation or mean over all probable events. In this case, the technique itself need not be modified to incorporate the probabilistic character of a problem. The adaptation may be complicated for some problems

[18] Narayan S. Rau et al., *Uncertainties and Risks in Electric Utility Resource Planning* (Columbus, OH: The National Regulatory Research Institute, February 1989), 23.

where the technique itself may have to be modified to enable it to solve a probabilistic problem.[19]

One noticeable development in operations research (OR) techniques is the incorporation of the capability to solve problems with multiple objectives. The more advanced OR techniques may be appropriate for utilities with large systems, significant resource diversity, and multiplicity of corporate objectives.[20]

Enumeration Techniques

Although optimization techniques can yield reasonably precise values of objective functions, such precise evaluation may not be very useful to the utility planner for several reasons. Regardless of how exhaustive a set of variables and parameters have been used to formulate the optimization problem, it may still be difficult to achieve the desired degree of comprehensiveness in problem formulation. One difficulty may be that not all variables are quantifiable. Another difficulty is that expanding the list of variables may make the problem mathematically unwieldy.

A useful, but mathematically less rigorous way to cast the planning problem is to evaluate functions of interest, such as total costs, revenue requirements, or customer rates, under different assumptions about parameters. The goal is to generate a list of alternative plans and values of objective functions rather than conducting a mathematical search for the optimal plan. The plans then can be compared on the basis of such known performance indices as cost and pollution reduction. The comparison can be supplemented with other considerations which may be qualitative and subjective. The usefulness of such heuristic planning has become more apparent as utilities are confronted with a set of market and regulatory challenges which may not be amenable to a rigorous mathematical optimization. Scenario analysis and decision-tree analysis are two well-known enumeration techniques.

One way to treat variability of forecasted outcomes is to list alternative scenarios and

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[19] Stochastic dynamic programming involves using probability weighted values at each decision point rather than a single statistical expectation.

[20] Electric Power Research Institute, *Operational Procedures to Evaluate Decisions with Multiple Objectives* (Palo Alto, CA: Electric Power Research Institute, September 1987).

evaluate how individual plans or strategies perform under each scenario.[21] If probabilities can be specified for various scenarios, then a quantitative evaluation of alternative plans is possible. This requires a single integrated framework that specifies the relationships of decisions, scenarios, and final values of the objective function. Such a framework is the decision tree.

Figure 3-2 is a decision-tree representation of the clean air compliance problem. In the tree diagram, a small square represents a "decision node" and a small circle represents an "event node." The figure shows two decision alternatives, "build scrubber" and "cofire with gas" for a coal-fired plant. The event node branches out into two scenarios each for the prices of coal and gas. The decision tree allows the computation of a specified function for all possible combinations of decisions and scenarios. Each of the endpoints in Figure 3-2 represents the expected value of a specified function for a given combination of decisions and scenarios. These endpoint values provide a comparison of a certain performance attribute (an objective function). The decision-tree framework can be used to compare any desired number of such attributes for a set of candidate plans.

Decision trees are helpful for risk analysis. For example, Figure 3-2 shows how the total revenue requirements vary for different combinations of decisions and scenarios. The difference of an endpoint value from the endpoint value represented by

[21] Scenario analysis at this stage is different from the scoping of scenarios discussed previously. Here, the scenario analysis is focused on the likely outcome of viable plans rather than a scoping analysis to determine which scenarios are more important or likely.

Fig. 3-2. Decision tree with hypothetical revenue requirements under different scenarios for two compliance options (Source: Authors' construct).

the most likely combination of scenarios may be helpful in estimating the risk of an option. For example, if the total revenue requirement is chosen as the objective function, the deviation of the largest endpoint value from the most likely value can be taken as a measure of risk for an option or a plan. With such a measure, the utility analyst may be able to develop a ranking of plans or options that can be used to establish a set of promising options.

Managing Risks

Decision trees and other analytical tools may be used to develop a risk-management strategy for compliance planning. However, it is not the sophistication of the analytical tool, but the risk-management goal set by the decisionmaker that may determine the choice of the strategy. The goal can be generally cast in two basic forms: performance optimization or risk minimization.

Performance Optimization as a Risk-Management Strategy

This strategy sets up an objective function to be optimized (maximized or minimized) under a chosen set of expected scenarios. Some objective functions that suggest themselves are profits or the internal rate of return (to be maximized), the present value of revenue requirements (to be minimized), and the levelized cost of compliance (to be minimized).

Mathematically, this method attempts to choose the plan with the largest (or smallest) value of the statistical expectation of the objective function. This method is generally well understood and perhaps most commonly used in problems involving statistical variation. The underlying rationale of this method is that the plan may do reasonably well under all anticipated scenarios although it may do poorly under any one scenario.

As a risk-management approach, this method becomes more effective if applied repetitively, since a statistical average tends to yield a better result, due to the cancellation effect of random fluctuations, with a large number of replications. In the utility context, this implies that the objective will be optimized in the long run, even if there are positive or negative deviations from the optimum in individual planning periods. Using this approach, the utility may do well in one planning period and poorly in the next but the overall performance (as measured by the chosen objective function) is expected to closely approximate the optimum over the long run.

However, there may be a number of reasons why a utility may not choose the expected value of a performance-based function as an objective to be optimized. Under the current regulatory arrangement, the utility may not expect to gain as much from successful outcomes as it expects to lose from unsuccessful ones. The utility may not be able to increase its profits beyond a certain limit because of the rate-of-return constraint even if it carries out a successful compliance plan. On the other hand, the utility may be penalized by retrospective cost disallowances for an unsuccessful compliance plan. This makes the regulatory risk-reward structure asymmetric to the utility. This asymmetry may invalidate the rationale for using the statistical mean of a performance-based function or index as an objective. This is true because the use of the statistical mean presumes a certain degree of symmetry with respect to favorable and adverse outcomes.

A utility, concerned with both short-term and long-term outcomes, may not choose the risk-management attributes of the above approach. There are other approaches, however, to risk management that the utility may consider instead.

Risk Minimization as a Risk-Management Strategy

Rather than attempting to optimize a performance-based objective function, the utility may choose to minimize a risk-based objective function. For example, the utility may choose to minimize the *variance*, rather than the expected value, of the present value of revenue requirements. Such an approach attempts to shield the utility from adverse regulatory or financial consequences of significantly higher or lower than anticipated revenue requirements. As another example, the utility may choose to avoid investments in control options that require significant amounts of capital to minimize the risk of retrospective disallowances.

A risk-minimization approach may not best serve the interests of the ratepayers, even though it may be perceived as a rational alternative to the utility. The utility may choose to put a greater weight on the possibility of an adverse outcome than on the likelihood of a favorable outcome. While such an approach may be perceived as overly risk-averse, the approach may be consistent with the presence of an asymmetric risk-reward structure in the regulatory arrangement. The utility may expect to be penalized with a greater severity for an unsuccessful outcome than rewarded for a successful one. Under such an arrangement, the expected value of a performance-based function may no longer be the appropriate objective to be optimized. Therefore, it may be more likely that a utility will attempt minimization of a risk-based objective rather than attempt optimization of a performance-based objective. However, this causes the utility interest to deviate from ratepayer interest. Therefore, asymmetry in the regulatory risk-reward structure, as inherent features of rate-of-return regulation, may distort the compliance planning process to the detriment of the ratepayer.

Incorporating Robustness and Flexibility as Risk-Management Strategies

There may be other risk-management approaches, besides optimizing the expected values of performance-based or risk-based objectives, which can be incorporated into compliance planning. They may involve evaluating plans for robustness and flexibility.

As noted, a plan is characterized as robust if it performs reasonably well under all likely scenarios even if it does poorly under any one scenario. As previously discussed, a plan that optimizes the expected value (statistical expectation) of a performance-based objective has this property over the long run. To incorporate the property of robustness into a plan over the short run, an *additional* evaluation criterion can be introduced that measures the deviation of the poorest outcome from the most likely outcome. In a previous section, this criterion was defined as a measure of risk (to be minimized in a risk-minimization strategy). Robustness of a plan may be defined as the inverse of the risk measure. Then, the optimal plan is chosen on the basis of the best combination of a performance-based criterion and a robustness-based criterion.

The difference between risk-minimization and robustness-based approaches lies in how risk is treated in the two approaches. In a risk-minimization approach, the risk measure becomes the objective to be minimized. In a robustness-based approach, the risk measure (or its inverse, the robustness measure) is a supplementary criterion to the chosen performance-based criterion. If two plans are otherwise equivalent on the basis of a performance criteria (they have objective function values that are fairly close within the bounds of statistical errors), the one with a higher robustness measure (or lower risk measure) is chosen.

Another approach to incorporating a risk-management goal into the planning strategy, is to include a measure of flexibility to supplement the performance criterion. Flexibility may be defined as the ability to depart from a prespecified plan without incurring high costs in response to future events. For example, investing in equipment (such as a scrubber) may generally be considered less flexible than making a change in plant operations (such as gas cofiring or switching to low-sulfur coal) or buying allowances. If in the future the price of allowances are low compared to scrubbing costs, the utility may find it hard to switch to a lower cost option without being left with the consequences of a stranded investment. On the other hand, if the utility chose fuel switching now and was faced with an allowance price higher than the incremental cost of scrubbing in the future, the utility could still choose to install a scrubber without incurring significant additional costs.

Unlike robustness, flexibility may be harder to quantify. Two definitions have been suggested in the utility literature. Mitnick[22] defines the value of flexibility as the difference in expected values of a cost criterion for two cases. In one case, the expected value (for a set of alternative scenarios) is calculated for an option without considering a change to another option for a specific scenario. In the other case, the expected value incorporates the cost changes due to changing from one option to another. Using this case, Mitnick shows that coal switching has a higher flexibility value than scrubbing even though scrubbing has a lower expected cost if

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[22] Steven Mitnick, "To Scrub or Not to Scrub: The Hidden Risks of Inflexibility," *The Electricity Journal* (January/February 1992): 44-49.

flexibility is ignored. Hobbs et al., suggest another measure of flexibility.[23] Hobbs defines the flexibility benefit as the difference between the most favored and the least favored outcome of a plan. In specific cases, the two definitions may coincide.[24]

It is interesting to observe the relationship between the definitions of robustness used earlier and the Hobbs definition of flexibility. Robustness may be said to measure the deviation of the least favored outcome from the most likely outcome. Flexibility, according to Hobbs, measures the total spread of outcomes. Therefore, based on the two definitions, it is possible to judge a plan as robust but not flexible and vice versa. It is also possible to have a robust plan which is also flexible. Further development of the measures of robustness and flexibility, as well as their relationship merit further investigation.

The analyst, however, is cautioned against using the above definitions alone to measure either the robustness or flexibility of a plan. The measures may be strongly sensitive to data assumptions about capital and fuel costs, allowance prices, and probabilities of scenarios. For example, a certain combination of data assumptions may lead to a result that makes scrubbing appear more flexible than fuel switching. Also, robustness, not flexibility, may be ultimately what is desired in a plan. Furthermore, using the suggested definitions, the relationship between robustness and flexibility cannot be clearly specified in spite of the intuitive belief that flexibility contributes to robustness. Therefore, although the above definitions are certainly useful and should be used to develop compliance plans, they need to be supplemented with subjective and qualitative judgments about robustness and flexibility. Future developments in this area of analysis may produce mathematically more rigorous measures of robustness and flexibility that can be used with more confidence in utility compliance planning.

Integrating the Compliance Plan with the Integrated Resource Plan

[23] Benjamin F. Hobbs, Jeffrey C. Honious, and Joel Bluestein, "Flexibility: The Case for Cofiring," *The Electricity Journal* (March 1992): 40-46.

[24] The Hobbs' definition does not require an explicit consideration of substitution of compliance options.

The compliance plan developed by a utility needs to be integrated with the utility's overall integrated resource plan (IRP). A compliance plan which is least cost on a stand-alone basis may not be least cost when the total resource cost either to the utility or to society is considered. Consistency requires that compliance options and resulting costs are integrated into the evaluation of demand and supply side options of the total utility resource plan. Such integration may be accomplished by examining the IRP process and identifying IRP elements that are affected by the compliance planning process.

Overview of the IRP Process

Figure 3-3 shows the basic elements of the IRP process. The process generally begins with a baseline load forecast of the utility based on customer end use, weather and other supporting data, and the DSM programs currently in place. Next, the effect of proposed DSM programs or options on projected load is evaluated. The adjusted load forecast, along with existing supply side options, become the basis for assessing future capacity and energy needs. Based on such needs, a candidate portfolio of supply side options, which may include both generation plants and purchased power is chosen. The resulting mix of existing and future generation plants and power purchase options is used to calculate future production costs. The acquisition of resources also involves raising and servicing capital to support such investments. The resulting financing costs are added to production costs and other operating costs to arrive at the revenue requirements. A cost-of-service allocation of revenue requirements, perhaps supported by a DSM-based pricing strategy (such as peak-load or time-of-use pricing), leads to customer rates. More advanced IRP analysis would also simulate the price elasticity

Note: Dotted arrows show the role of compliance options in the IRP process.

Fig. 3-3. Integrated resource and compliance planning (Source: Authors' construct).

effect of customer rates on customer demand, resulting in an iterative analysis of the entire process.

The objective of the IRP process is to find an optimum (if a single objective can be defined and if there are no uncertainties) plan or a strategy (when there are multiple objectives and planning parameters are uncertain) that attempts to minimize a cost objective and assure a certain level of performance, including reliability.

Incorporating Compliance Planning in the IRP Process

The introduction of compliance planning, although expanding the scope of and adding analytical complexity to the IRP process, still has attributes that are conceptually similar to the IRP process. Compliance with the CAAA requires the acquisition of resources and optimal use of resources the same way the pre-CAAA IRP process does. The final goal is still to minimize a chosen cost objective that assures a certain level of performance. By definition, an IRP process requires that the costs and performance of all resources, whether to meet energy needs or to achieve environmental compliance objectives, should be evaluated for selection of utility options. Therefore, consistency requires that compliance planning not be done in isolation, but as an integral part of the IRP process.

A first step to incorporating compliance planning in the IRP process is to identify elements of the IRP process that have compliance consequences or are affected by compliance actions. For example, the choice of a DSM program affects the level of energy generation and future need for capacity, both of which affect the compliance requirements of a utility. Further, a DSM program that is part of a commission-approved IRP may be entitled to bonus allowances from the EPA which can be used to offset compliance requirements. As another example, including a retrofit boiler to a coal-fired plant, a possible compliance action, adds to the financing costs and the operating costs of the utility and contributes to the total revenue requirements, an important IRP cost objective. Figure 3-3 shows compliance consequences of various elements of the IRP process and also the effect of possible compliance actions on an IRP cost objective, the total revenue requirements. The conceptual IRP framework depicted in Figure 3-3 can be used to carry out the analysis of demand-side, supply side, and compliance options. The analysis is similar, albeit significantly extended in scope and complexity, to the analysis generally used for pre-CAAA IRP evaluations.

Data Requirements for Evaluating Utility Compliance Plans

Evaluation of compliance plans requires access to a significant body of data on forecasts, existing utility resources, future acquisition of resources, system operations, and the utility financial plan. Most of these data are routinely submitted to state commissions in regulatory proceedings for approving a utility IRP, for approving specific plants and investments, or for approving DSM programs. For evaluating compliance plans, a public utility commission needs access to additional data that are specifically associated with pollution control options, the utility's allowance position and trade options, and the utility's strategy for dealing with uncertainties and risks. The following is a list of broad data requirements for evaluating compliance plans:

1. list of existing affected sources and emissions both under phase I and phase II;
2. allowances currently held by the utility;
3. utility's projection of future capacity and energy needs;
4. utility's proposed mix of generation and power purchase options with associated cost and engineering data;
5. data on additional emissions from future capacity additions;
6. utility's existing mix of retrofit, repower and fuel switching options, and associated cost and engineering data;
7. utility's proposed mix of retrofit, repower and fuel switching options, and associated cost and engineering data;
8. existing power purchase contracts and associated data;
9. utility's proposed plan for buying, banking, and selling allowances;

10. utility's proposed plan for holding an allowance reserve to meet unanticipated contingencies;
11. existing contracts for the sale or purchase of allowances and associated data;
12. utility's forecast of fuel and allowance prices;
13. methodology and assumptions used to develop the compliance plan and other studies that support and validate the methodology and assumptions;
14. methodology and assumptions used to integrate the compliance plan with utility IRP;
15. detailed data and analysis of how cost and performance of compliance options were ranked;
16. summary descriptions of computer models used in developing and analyzing the utility compliance plan (including flow charts, algorithms, input requirements, and outputs produced) and any reference and other studies that support the reliability, accuracy, and usefulness of the computer models;
17. range of uncertainties in load forecasts, DSM program costs, DSM effectiveness in reducing compliance requirements, construction costs and lead times for retrofit control technologies and new capacity, fuel prices, allowance prices and financing needs of the utility used to develop the compliance plan;
18. data showing how the chosen plan would fare over the range of uncertainties listed in 17 (this should include the impact on revenue requirements and customer rates);
19. data on future impact of existing and proposed DSM programs in reducing future load and compliance requirements and data on projected bonus allowances to be received to offset compliance requirements; and
20. data on renewables similar to those listed in 19.

After receiving this information, the commission may reserve the ability to direct the utility to do additional calculations and run additional scenarios.

Summary

The approach described in this chapter is intended to assist public utility commissions in determining and analyzing the steps involved in a compliance strategy. The steps described here include:

1. establish compliance objectives,
2. conduct a scoping analysis of scenarios and options,
3. conduct a cost analysis of options,
4. develop a least-cost set of options for a chosen set of scenarios,
5. conduct an analysis of uncertainties and risks (analyze options under different scenarios),
6. develop a set of compliance plans, and
7. integrate compliance plans with the overall utility resource plan (if one exists).

The commission can choose how involved in this process it wants to become based on how similar resource choices are made. For example, the commission may collect the data and conduct a parallel analysis or simply review the utility's analysis.

Chapters 5, 6, and 7 present alternative ratemaking approaches. A distinguishing feature of these approaches is the varying level of incentives the utility receives to minimize its compliance costs. An incentive mechanism, such as the one presented in Chapter 6, can encourage a utility to pursue and adopt cost-effective compliance strategies with less commission oversight than other approaches.

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CHAPTER 4

REGULATORY ACCOUNTING OF ALLOWANCES AND COMPLIANCE COSTS

The introduction of a market-based system for achieving an environmental objective presents regulators with a challenging situation, one which may warrant the implementation of new regulatory treatments in order to ensure that utilities adopt least-cost compliance plans. In previous NRRI reports[1] it was suggested that some form of incentive regulation and/or different regulatory accounting approaches may need to be adopted to achieve this goal. Before one can assess whether or not conventional ratemaking practices will suffice, a framework should be established for understanding the regulatory options that commissions now face. This chapter describes the ratemaking and regulatory accounting options that commissions have available to them in defining cost recovery treatments for utility compliance plans and allowance transactions. This chapter also looks at the mismatch between traditional rate-of-return regulatory approaches and the CAAA's market-based approach to environmental regulation.

In developing regulatory policies for the treatment of compliance-related utility activities, commissions will have to answer five general questions:

1. How are the utility's standard compliance costs to be recovered (that is, the expenses and capital expenditures associated with compliance activities)?
2. How should the utility's initially allocated allowances be valued?
3. What accounting and regulatory policies should be implemented for valuing and capitalizing the utility's allowance bank/inventory?

[1] Kenneth Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, 1992); and Kenneth Rose and Robert E. Burns, eds., *Regulatory Policy Issues and the Clean Air Act: Issues and Papers From the State Implementation Workshops* (Columbus, OH: The National Regulatory Research Institute, July 1993).

4. How should allowance purchase costs be treated?
5. How should allowance sale revenues be treated?

It is difficult to cleanly divide the regulatory decisions into distinct, separate questions or categories since there is a great deal of overlap among these different areas. However, given that commissions are facing so many alternatives, this chapter attempts to organize these issues into a relatively structured framework in order to clarify the decisions that commissions will have to make. Therefore, the following five sections provide a framework for the above questions:

1. Compliance Costs
2. Allocated Allowances
3. Allowance Bank/Inventory Valuation
4. Allowance Purchase Costs
5. Allowance Sale Gains or Losses

Compliance Costs

For this discussion, a utility's compliance costs are those capital expenditures and annual expenses that are incurred to reduce acid rain emissions and comply with the CAAA. The compliance costs discussed in this section do not include the costs of allowance purchases. The treatment of allowance purchase costs will be discussed later. However, the compliance costs defined here include the costs that may be incurred to overcontrol emissions. Hence, there is some overlap with the allowance inventory and allowance sale ratemaking issues.[2]

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[2] Because of the flexibility provided by the CAAA, a utility may choose to reduce its annual emissions below its level of allocated allowances (that is, overcontrol its emissions), thereby freeing up allowances for possible sale.

Compliance costs can be: (1) ratebased, (2) expensed, (3) deferred, or (4) set aside (or uncoupled) into separate accounts for either unregulated or deferred revenue purposes.

Ratebasing: Traditionally, the capital expenditures associated with productive, inservice utility assets are placed in "rate base," where each year's balance (net of accumulated depreciation) earns a fair rate of return. Such treatment would be the likely arrangement for compliance-related capital costs (for example, the construction costs for scrubbers, precipitator upgrades, repowered boilers, extensive fuel-handling system modifications).

Expensing: Ongoing utility costs (such as fuel costs, purchased power costs, and operation and maintenance costs) tend to be charged through to ratepayers on an "as spent" basis. This can either be done through base rates or in some cases a periodic adjustment clause. Presumably, the annual ongoing costs of emissions reduction (for example, low-sulfur fuel costs, the costs of scrubber reagents and waste disposal, and so on) would be expensed.

Deferring: Occasionally, commissions seek to mitigate the rate impact of large projects or unusual circumstances by establishing deferral or balancing accounts. These accounts permit costs to be recovered in different years or over different timeframes than would normally be the case.

Uncoupling: Either capital costs or annual expenses potentially can be set aside in a separate stockholder account. This is typically done for nonregulated utility ventures, where the stockholders' investments do not receive any utility rate recovery. The stockholders bear all of the risk of such ventures and receive all of the gains. Similarly, an account could be established to set aside costs of compliance activities that were unregulated investments.

As an example of the last treatment, a utility might build a scrubber solely for generating excess allowances for sale. Provided that the utility's regulatory commission agreed to such an arrangement, the cost of the scrubber could be isolated from the traditional rate recovery in exchange for the stockholders getting most or all of the gains from the allowance sales. The advantage of this uncoupling approach is that it clearly distinguishes between a utility's allowance-generating activities and its emissions-reduction activities that must be performed to comply with the CAAA. It also could be used to directly associate the gains and losses from these uncoupled activities with the stakeholders whose investment is at risk. Those stakeholders could be the utility's stockholders, ratepayers, third parties, or some combination of these groups. Although in theory this approach should provide for an easy delineation of regulated and unregulated costs, regulators would have to be careful to ensure that cross-subsidization did not occur (that is, where unregulated activities are supported indirectly by regulated operations). Within the context of either the ratebasing or expensing methods, a commission has additional options for controlling rate recovery and, in some instances, providing a utility with incentives such as:

1. deferring/phasing-in costs,
2. accelerating cost recovery,
3. reducing regulatory lag,
4. allowing construction work in progress (CWIP) in rate base,
5. imposing cost caps,
6. establishing cost targets with split savings/losses, and
7. increasing allowed rate of return.

These approaches were previously used in other areas of utility operations. However, their use in compliance-related ratemaking treatments will not be the focus of this report.

Allocated Allowances

Starting in 1995, phase-I-affected utilities will receive allowances from the U.S. Environmental Protection Agency (EPA). Each utility will receive an annual quantity of allowances in the form of its basic allocation. In addition, a utility may be eligible to receive bonus allowances from EPA if the utility implements specific compliance activities favored in the CAAA. Some have recommended that the basic allocations and bonus allocations should be kept in separate accounts to allow for different cost bases or regulatory treatments. This point of view is supported by the fact that affected utilities are allocated their basic allowances regardless of their compliance activities. However, to be eligible for bonus allowances, utilities must undertake specific activities (that is, conservation, scrubbing with at least 90 percent efficient technology, and so on). These activities have distinct costs. Therefore, while the basic allowance allocation may be free, the bonus allowances that a utility receives should have a cost basis that reflects the investment (often borne by ratepayers) that was required to obtain these allowances.

The creation of separate accounts for allocated allowances and bonus allowances was not endorsed by the Federal Energy Regulatory Commission (FERC) in its recent accounting rulemaking.[3] Separate treatment of the two types of allowances may not be justifiable or desirable because the decision to bank, sell, or consume an allowance from a utility's inventory should not depend on its origin. This decision should be based on the prevailing allowance market prices and the utility's overall circumstances (examples include, internal compliance options, customer load requirements, and bulk power market opportunities). With some minor exceptions, allowances are fully fungible, and one allowance is no different from another. Therefore, the creation of separate accounts and the adoption of different cost bases could potentially distort the proper

[3] Federal Energy Regulatory Commission, "Revision of Uniform System of Accounts for Allowances under the Clean Air Act Amendments of 1990," Docket RM92-1, Order 552, March 26, 1993.

management of allowance inventories by introducing accounting biases. In any event, EPA will not charge a utility for either the basic or bonus allowance allocations.

The most reasonable regulatory approach for a utility's allowance costs is to expense them when they are consumed and to place any excess allowances[4] in an allowance inventory. The question then becomes one of establishing a cost basis for the allowances. Presumably, this cost basis would be included in the utility's revenue requirements for those allowances consumed in a year and would be used for inventory valuation for those allowances that were banked. For allowances that are purchased in the allowance market, the purchase price can serve as an appropriate cost basis (as is discussed below). However, the EPA-allocated allowances do not have an acquisition cost.

A commission potentially could select any of the three following rules for establishing a ratemaking value for a utility's EPA-allocated allowances. The cost basis could be:

1. zero (that is, an historical cost basis, as has been suggested by FERC in its rulemaking), since the utility is not charged anything for them,
2. market price or some other determined value (as has been discussed in an earlier NRRI report[5]), since allowances are valuable assets and should not be valued at zero, or
3. the utility's cost of compliance (average or marginal).

[4] That is, those not used to cover the current year's emissions.

[5] Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program*, Chapter 9.

The rationale for a zero cost basis is that the utility will receive all of the allowances from EPA at no charge. Critics of this approach contend that the utility will not be motivated to efficiently utilize allowances if they have no cost. As is discussed later, if a utility saves zero-cost allowances and places them in a ratebased inventory account (in which a return is earned on the balance), the utility will not receive any benefits. The balance would be zero, so the return would be zero. The number of allowances in inventory could grow or shrink without having any effect on the company's earnings.

In conjunction with a market-price cost basis, it was suggested that the utility "buy-into" the portion of the allowance allocation deemed to be owned by the utility's ratepayers. In effect, the stockholders would purchase these allowances from the ratepayers at market price through a rate reduction. If allowances were consumed, the cost of these allowances would be expensed through a rate increase. These first two approaches will be referred to as *total allocation* accounting methods; where the first approach values the allowances at the acquisition cost (zero), while the second values allowances at the market price.

The average- or marginal-cost-of-compliance cost basis could be used to value *excess* allowances generated by a utility. This approach, which will be referred to as the *excess allowance* accounting approach, moves away from the idea of valuing an affected utility's *entire* EPA allocation of allowances. Instead, attention is focused only on those end-of-year excess allowances that are freed up because the utility overcontrolled its emissions. The *marginal* costs of overcontrol incurred in reducing a utility's emissions below its stipulated allowance allocation could form an appropriate basis for valuing these *excess* allowances. Those allowances consumed during the year would have a zero cost basis, while any allowances that remained at the end of the year would be the result of overcontrol (or allowance purchases) and would have a cost basis that could be directly attributed to them. Presumably, these costs would be those associated with the utility's highest-cost compliance options (and/or any allowance purchases).

Allowance Bank/Inventory Valuation

There are five major issues that commissions will have to address concerning allowance inventories:

1. the "partitioning" of a utility's allowance inventory,
2. the determination of what constitutes an allowance inventory,
3. the valuation of additions to inventory,
4. the valuation of withdrawals from inventory, and
5. whether or not the allowance inventory should earn a return like other ratebased inventories.

Partitioning Allowance Inventories

Unlike most commodities, allowances have dates associated with them that restrict their usage. Allowances that are part of a utility's 1998 allocation cannot be consumed until 1998 or later. However, such allowances can be bought and sold at any time. Therefore, for ratemaking and accounting purposes, separate allowance inventory accounts are recommended to be established for each year's allowance allocation.[6] Once the true-up period[7] for a particular year is over, all remaining allowances for that year will be transferred to the next year's inventory. This partitioning of the allowance inventory will prove beneficial in establishing appropriate ratemaking treatments. For example, assume that in 1995 a utility purchases 10,000 current allowances to cover its 1995 emissions, and 10,000 1999 allowances. The 1999 allowances cannot and should not be mixed in with the utility's 1995 allowance inventory, since these 1999 allowances cannot be used in 1995. Likewise, the ratepayers in 1995 should not have to pay the entire purchase costs for all 20,000 allowances; instead, they should only pay for the allowances they consume in 1995. The purchase costs for the 1999 allowances should be isolated in a different account and expensed

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[6] EPA is maintaining a thirty-year account for all allowance holders; utilities and commissions may want to adopt the same arrangement.

[7] EPA has designated that a thirty-day true-up period will follow each calendar year; utilities must have enough allowances to cover a calendar year's emissions by the end of the true-up period (January 30 of the following year).

at that time in the future when those allowances are used.

For the remainder of the report, it will be assumed that any references to allowance transactions refer to the purchase or sale of allowances usable in the current year. All of the regulatory treatments examined in this report can be applied to the multiyear partitioned inventory arrangement described above. However, such considerations add an element of complexity that will be set aside for future research to simplify this report's ratemaking discussion.

Allowance Inventory Determination

As just described, the excess allowance accounting perspective views a utility's allocated allowances as tradeable assets that only have value if the utility is able to reduce its annual emissions to a level below its allocation and thereby free them up for sale or later use. This effectively represents a policy whereby a utility's initially allocated allowances are reserved first for current-year consumption in the utility's operations. Conversely, a total-allocation accounting approach views a utility's total-allocated allowances as assets from the start, regardless of the current year's operations.

These two approaches lead to distinctly different definitions of what constitutes an allowance inventory. The excess allowance approach lends itself to an end-of-year determination--when a utility's emissions are finally known and the remaining allowances can be calculated with certainty. This remaining balance is the utility's inventory and can be carried forward to the next year. Thus, by this perspective, phase I utilities will not have allowance inventories until the end of 1995. This is not to suggest that a utility cannot sell any 1995 allowances until after 1995. Indeed, an affected utility can sell any of the allowances in its EPA account at any time. From a ratemaking standpoint, if a utility sold allowances from a "yet-to-be-created" inventory, the revenues from the sale could be set aside in a prepayment account until the allowances were finally generated. At that point, the cost of the allowances and the gains or losses from the sale could be determined.

Although additions and withdrawals from inventory are discussed in detail below, a possible treatment of current-year allowance purchases and sales under the excess allowance approach should be briefly described at this point. As described above, the excess allowance approach leads to an end-of-year determination of allowance inventories. At this time, any purchases and sales of current-year allowances can be factored into the inventory calculation. Commissions may consider various approaches to handling multiple allowance sales and purchases within a year. One possibility would be to designate the lowest cost purchases for current year consumption, if a shortfall is experienced, with higher cost purchases being placed in inventory or providing the basis for any allowance sales that are made during the year. Such treatment would be consistent with the objective of reserving the least-cost compliance activities for a utility's current ratepayers. The more expensive activities would go toward the creation of inventory for sale or later use.

For example, assume that a utility projected that its emissions would exceed its allowance allocation by 10,000 tons. During the course of the year, the utility made the four allowance transactions presented in Table 4-1.

TABLE 4-1

EXAMPLE ALLOWANCE TRANSACTIONS

Month	Transaction Type	Number of Allowances	Price
January	Purchase	10,000	$250
February	Purchase	10,000	$275
March	Purchase	10,000	$270
December	Sale	15,000	$300

A commission may decide to "package" these transactions in the following manner:

1. The January purchase of 10,000 allowances would be used to meet the current year's shortfall (since it was the cheapest) and its costs would be recovered in rates.
2. The December sale of 15,000 allowances would be drawn from the other two purchases. The most expensive purchase, February's, would be entirely allocated to

the sale along with half of the March purchase.

3. The 5,000 allowances remaining from the March purchase would be placed in the utility's end-of-year allowance inventory.

The alternate perspective on allowance inventories, the total allocation approach, views the utility's total initial allowance allocation as the allowance inventory; hence, the utility's inventory can be determined at the beginning of a year, or anytime during the year. This perspective is a more traditional approach. However, it best applies to conventional types of assets or commodities, like utility fuel inventories, where tangible, periodic deliveries are made to satisfy a more or less continuous demand. Allowances are unique. First, the federal EPA has already determined what affected utilities will receive in their basic annual allowance allocations. Thus, the concept of tangible deliveries does not apply since utilities know their allocation years in advance. Second, utilities will receive these allowances at no charge. Third, they do not need to maintain an allowance inventory during the course of the year; utilities only need their allowances at the end of a year's true-up period (January 30th of the following year). Therefore, in deciding inventory issues, such as whether or not a utility should be allowed to earn a return on its allowance inventory, regulators must first recognize the unique nature of allowances and specifically decide what constitutes an allowance inventory.

Additions to Inventory

If the excess allowance approach is used, additions to inventory would include any surplus of a utility's basic allocation at the end of a year, plus any current-year allowance purchases. With the total allocation approach, additions to inventory would comprise a utility's total annual allowance allocation, plus allowance purchases. The valuation of additions to inventory entails some of the same issues that were addressed above (see the section on "Allocated Allowances"). To recap, purchased allowances should probably be valued at their market price. Commissions have three options for valuing the allowances received from EPA, both basic allocation allowances and bonus allowances. Allowances can have a cost basis that is:

1. historical (that is, zero),
2. a market-based value, or
3. a cost-based value that is calculated from the utility's cost of compliance.

The third option makes sense if one adopts the excess allowance approach to allowance valuation. The costs associated with overcontrol options would be used to value any unused allowances from a year's basic allocation. Those costs would then be carried into the following year's inventory, and excluded from rate recovery until the allowances were subsequently consumed or sold.

Withdrawals from Inventory

The valuation of withdrawals from inventory depends on which of the following inventory accounting conventions are employed:

1. the Weighted-Average Cost methodology,
2. the Last-In-First-Out (LIFO) methodology, and
3. the First-In-First-Out (FIFO) methodology.

Weighted-Average Cost

FERC's Order 552 endorses the use of a weighted-average inventory convention. This methodology considers the cost of any allowances withdrawn from the inventory to be the average of the costs of those allowances that were in the bank at the time of the withdrawal. The costs of any additions to inventory, in the form of annual allocations or allowance purchases, would be rolled into the average cost calculation at the time of the addition. One of the primary benefits of this methodology is that it would eliminate any accounting differences among individual allowances that were held in the current inventory. This would minimize any distorting incentives for the utility to time the purchase or sale of allowances in order to achieve temporary accounting gains. One of the drawbacks of the weighted-average-cost methodology is the unusually low value that it places on allowances, if a utility's basic allowance allocation is added to the inventory at a zero value. Considering that allowance purchases probably will comprise a much smaller portion of a utility's inventory than its basic allocation, the value of any purchased allowances will be "watered down" by the zero value of the basic allowances. For example, assume that a utility had a basic allocation of 100,000 allowances and purchased an additional 10,000 at a price of $300 per allowance. The resulting inventory would have a total value of $3 million[8] and an average inventory cost of only $27 per allowance.[9] Depending on the other regulatory treatments that a commission implements, this low value could have negative ratemaking repercussions. For example, if the commission uses the weighted-average inventory value to determine gains or losses on the sale of allowances, the result would most likely be a windfall gain for a selling utility since the market price is likely to be several times the inventory value. Another important drawback is that given the assumption that the market price of allowances is

[8] $3 million = (100,000 allowances x $0/allowance) + (10,000 allowances x $300/allowance)

[9] $27/allowance = $3 million/(100,000 allowances + 10,000 allowances).

$300, the $27 figure does not provide an accurate representation of the true value of an allowance or the firm's assets.

The excess allowance accounting approach to allowance valuation might use a modified version of the weighted-average-cost method. An end-of-year comparison could be made between a utility's current-year allowance allocation and its emissions. If the utility netted a surplus, these allowances could be valued on the basis of the utility's marginal cost of overcontrol.[10] They could then be added to any existing inventory balance that was being carried forward from previous years, as well as any current-year allowance purchases. The total value of the inventory would be divided by the number of allowances in the inventory to determine a weighted-average cost. This could be the basis for any current-year sales. If the end-of-year comparison showed that the utility had exceeded its annual basic allocation, then the deficit would have to be satisfied by either current-year purchases or the inventory carried forward from the previous year (or a combination of both sources). In keeping with an average-basis methodology, these two sources should be added together to calculate a weighted-average allowance value. This combined inventory would be used to satisfy the current year's deficit. Any remaining allowances could be applied toward current-year sales and/or carried forward to the next year. The benefit of this modified weighted-average-cost method is that it would preserve a more realistic value of the allowances in a utility's inventory and avoid the potential for windfall profits on the sale of allowances.

LIFO and FIFO methodologies

The LIFO methodology would dictate that a withdrawal of allowances from the inventory would be composed of the most recently acquired allowances. The FIFO methodology can be explained with a pipeline analogy: it would consider the withdrawal to be composed of those

[10] Costs that are being transferred to an allowance inventory account should be removed from other accounts to avoid double recovery. For example, if additional operating costs were incurred to generate excess allowances, these costs should be transferred to the allowance inventory accounts and taken out of the current expense account.

allowances that were next in line in the pipeline. Just like oil in a pipeline, the withdrawal would be composed of the allowances that had been in inventory the longest. In the cases of both LIFO and FIFO methodologies, the timing of additions and withdrawals from an allowance inventory has a more pronounced effect on the dollars-per-ton value calculated for withdrawals than the weighted-average approaches.[11] Consequently, they might lead a utility to buy or sell allowances strictly for accounting reasons. Such distortions and motivations would exist because the allocated allowances in the inventory will have a zero value (with historical valuation) while purchased allowances will have a (nonzero) market value. With LIFO or FIFO inventory accounting, it would be possible to exploit these dramatically different values to achieve accounting gains even though fundamental economics might favor a different inventory management strategy.

Earning a Return on Inventory

The last issue that commissions must address concerning allowance inventories is their status as ratebase assets. Some have suggested that allowance inventories should earn a return similar to fuel inventories. In the case of fuel inventories, most commissions consider such reserves as necessary investments that enable utilities to keep their generating systems running smoothly. The inventories are purchased and their levels are maintained through funds supplied by the utility's stockholders. The appropriate level of reserves is determined by the commission. This level is allowed ratebase treatment, and generally utilities attempt to stabilize their fuel inventories at or below these predetermined levels. The ratepayers compensate the stockholders

[11] Also, both methodologies require clarifying decisions about the timing of allowance allocations versus the carry-forward of previous years' surplus allowances. One perspective would be that all basic allowances for *every* year were "delivered" when the CAAA was signed into law in 1990. Thus, all of the allocated allowances are the first ones into each year's partitioned account. Another perspective might be that if a previous year's surplus allowances were being carried forward into the current year, the previous year's allowances would be considered the first ones into the inventory (since they were associated with an earlier year) rather than the current year's "newer" allowances. Adopting one or the other of these perspectives would yield different results for the LIFO and FIFO inventory methodologies.

by paying for all of the fuel that is consumed in a period (often through a fuel adjustment clause) and by paying a return on the allowable inventory balance.

Allowance inventories and fuel inventories share some similarities, although there are also considerable differences. First, a stable level of allowance inventory is not required throughout the year. In fact, a utility's allowance inventory can fluctuate significantly during the calendar year (even going negative at times). To comply with the CAAA, a utility must have merely enough allowances, as of January 30th of a given year, to cover the previous year's emissions. Conceivably, a utility could sell all of its allowances at the start of a year, incur an increasingly negative inventory balance through the year because of its on-going sulfur dioxide (SO_2) emissions, and purchase all of the allowances it needed by January 30th of the following year. By following such a strategy, a utility would eliminate its inventory carrying costs. Specifically, it would generate revenues that could be invested in an interest-earning account or activity for the year. Obviously, whether or not this strategy is profitable also depends on the price of allowances at the beginning and end of the year. The important points in this example, are that:

1. there is a carrying cost (in the form of an opportunity cost) for allowance inventories, and
2. allowance inventories do not need to be maintained at stable levels on a month-to-month basis.

Another difference between allowance inventories and fuel inventories is that utilities accumulate fuel inventories by purchasing fuel from a market while allowance inventories will be largely made up of allowances received from EPA at no charge. Thus, while the value of fuel inventories is easy to ascertain from the utility's purchase costs, valuing a utility's allowance inventory may not be as straightforward.

Inventory Turnover

If the initially allocated allowances are valued at zero cost, it may appear that the decision on whether or not to allow a return on allowance inventories is moot. After all, a return on a zero-cost asset is zero. However, even under that supposition, the return-on-inventory decision is still important. If sound ratemaking policies are not implemented, significant distortions in allowance trading activity could occur. For example, if a utility's allocated allowances are valued at zero cost and its allowance inventories are allowed to earn a return, the utility will have an incentive to sell its original allowances and simultaneously buy replacement allowances. If both transactions are carried out at the same price and quantity, the revenues and purchase costs will cancel out. The utility, however, will now have an inventory that is filled with market-priced allowances and can earn its return on this inventory. Regulators must be careful not to promote a scenario such as this that would result in the needless turnover of allowances. Commissions may easily detect an overt attempt by a utility to "churn" allowances. However, more subtle approaches, such as through affiliate transactions, may be more difficult to detect.

Who Owns the Inventory?

An important issue that commissions must discern in determining the ratebase status of allowance inventories is whether the inventory represents the investment of stockholders' or ratepayers' money. Fuel expenses are usually passed through to ratepayers and the utility is allowed a return on the (prudently determined) inventory value. As indicated by some states, allowances may be treated in a similar manner. Before this can be determined, however, one of the two allowance valuation approaches described above must be selected (the total allocation or excess allowance approaches). If the total-allocation of allowance valuation method is used, issues of beneficial ownership[12] must be analyzed to determine what portion of the initially-allocated allowances belongs to ratepayers. Such a determination might be based on the age or depreciated basis of a utility's affected plants. Presumably, only the portion of the allowance inventory that belonged to stockholders would earn a return. Since the ratepayers already own their portion of the inventory, they should not have to pay any carrying charges on it.

If one takes the excess-allowance perspective, the question of beneficial ownership is

[12] See Chapter 8 of Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program*.

applied to the excess allowances only. That is, they will be "owned" by those who pay, or have already paid, to free them up.[13] A utility's inventory balance could not be determined with certainty until December 31st of the year in question. Only at this time would the utility's actual annual emissions be known; and only at this time would the exact number of surplus allowances, that could be banked or sold, be known. If the utility's ratepayers had paid for *all* compliance activities through the course of the year (that is, capital investments had been ratebased, fuel-switching costs had been expensed, and so on), one could argue that the inventory of surplus allowances would belong entirely to the ratepayers.[14] If such is the case, this ratepayer-funded asset should *not* be part of ratebase: since the stockholders have not financed the creation of this asset, they are not owed a return. The value of the inventory could be based on the utility's marginal costs of overcontrol. After all, these marginal activities would represent the efforts that had generated the excess allowances. The revenues from any allowances that were sold from the inventory would go to the ratepayers.

If a utility wanted to pursue profitable ventures in the allowance market on the part of its stockholders, it could follow the same procedure. In this case, though, it would make investments in additional control measures by using the *stockholders*' money.[15] The operating costs and capital expenditures of the overcontrol options would not be recovered in rates; instead, such

[13] However, even if an overcontrol project is funded entirely by a utility's stockholders, the ratepayers may still be entitled to some of the project's economic benefits. This is especially true if the ratepayers will bear all of the costs for reducing emissions to reach compliance (that is, reducing emissions to the utility's allowance allocation), and thereby make the surplus allowances possible. This is obviously going to depend on the individual circumstances of the utility.

[14] This assumes that a rate case was filed to provide the utility with prompt repayment of compliance-related revenue requirements. Even under this condition, there is room to argue that the utility's stockholders are partial owners of the surplus allowances. Although they have been compensated for that particular year's costs, the stockholders may still hold most of the remaining investment in the project that generated the allowances (for example, a scrubber).

[15] The recovery of stockholder funds expended and the use of utility assets are issues that are likely to arise in a rate proceeding. Commissions may have to establish rules as to which activities are above the line and which are below and how this will be determined. See Chapter 8 of Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program*, for a discussion of this issue.

costs would come from the utility's earnings and would be isolated in a separate, unregulated account. The stockholders would "own" the excess allowances that were generated by these additional measures and would be the recipients of all proceeds from the sale of the excess allowances. As a third possibility, a partnership in the funding of overcontrol compliance activities could be arranged so that both ratepayers and stockholders could receive the potential benefits, and bear the potential losses in the allowance market. This type of partnership is described in Chapter 7.

Allowance Purchase Costs

The ratemaking options for allowance purchases are much more straightforward than the issues discussed above. Since, by definition, purchased allowances have a market-based cost associated with them, the recovery of the costs of purchased allowances is no different from the recovery of other utility expenses, such as fuel. Most agree that the costs of purchased allowances should be included in a utility's allowance inventory when the transaction occurs. When allowances are consumed, the appropriate expense can be charged to the ratepayers. If a utility uses the inventory valuation methodology proposed by FERC's rulemaking, the expense would be the average inventory value. This average value would include a portion of the costs of the purchased allowances.

Allowance Sale Gains or Losses

Some have estimated that an efficient allowance market could reduce the cost of national compliance in phase II by almost $3 billion per year in comparison to a "command-and-control" regulatory policy.[16] Some portion of these savings will be reflected in the gains that low-compliance-cost utilities realize on their allowance sales. State regulatory commissions will determine the extent to which these gains are either used to lower customer rates or to increase utility earnings. The commissions will have to balance the interests of ratepayers and stockholders in order to achieve the greatest benefits for the ratepayers. If none of the gains are given to the utility's stockholders, the utility may lack the incentive to pursue beneficial sales. If too much of an incentive is given, the utility's ratepayers will not receive as much of the gain as they could have.

In determining regulatory treatments for the sale of allowances, commissions will have the following options:

1. Gains or losses could be shared between ratepayers and stockholders or could be solely allocated to one group.
2. The gains/losses given to ratepayers could be used to reduce/increase the net plant balance of ratebased compliance projects or could be used to reduce/increase current year expenses.
3. The gains/losses given to ratepayers could be placed in a deferred account which would distribute the gains or losses over the course of a project's lifetime based on a predetermined arrangement.

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[16] Electric Power Research Institute, *Integrated Analysis of Fuel, Technology and Emission Allowance Markets: Electric Utility Responses to the Clean Air Act Amendments of 1990,* EPRI TR 102510 (Palo Alto, CA: Electric Power Research Institute, November 1993), 1-18.

The first option is merely a statement that the gains or losses from allowance sales could be shared between ratepayers and stockholders. Sharing some of the benefits of allowance transactions with a utility's stockholders may be necessary to promote appropriate utility actions. (The issue of incentive regulation is explored further in Chapters 6 and 7.) The second and third options listed above pertain to those portions of gains or losses that are directed to the utility's ratepayers. For clarity, the rest of this discussion will refer only to the gains that may result from allowance sales. Obviously, losses could occur as well. To the extent that they do, such losses will have the opposite effect that gains will, for example, they will raise customer rates while gains will reduce rates.

One option is for gains from allowance sales to be used to reduce a utility's ratebase. This might be a reasonable approach if the majority of a utility's compliance costs involved capital-intensive projects. Effectively, the benefit of a one-time gain would be spread over the remaining book life of the project by reducing the project's net plant balance in ratebase. Presumably, this deduction would be amortized in a straight-line fashion over the remaining book life of the project and would therefore benefit the utility's ratepayers over that entire period--in the form of reduced depreciation expenses and reduced return on ratebase obligations.

Similarly, gains from allowance sales could be deducted from the expenses of customer revenue requirements in the year the gains are realized. This could be performed most easily by passing the gains through a fuel adjustment clause, if available. This would be appropriate if the majority of a utility's compliance costs were fuel-related or allowance-purchase-related. Such ratemaking treatment would provide the current ratepayers with a one-year rate reduction in the year of the allowance transaction.

Balancing Accounts

The last option listed above involves the establishment of a deferred expense or deferred revenue account that would distribute the gains from an allowance sale, based on a predetermined arrangement. As will be shown later in this chapter, the revenue requirements from a capital-intensive compliance activity generally decline over the life of the project. Hence, the cost basis of allowances generated from such an activity is likely to be greater in the early years than in later years. If allowance prices increase over time, this could result in losses that would be incurred by allowance sales during the early years of an otherwise cost-effective project. Over a longer timeframe, the project may be very profitable, with later allowance sales reaping considerable gains. However, this would mean that the current ratepayers would bear the early losses while future ratepayers would reap the benefits of the later gains. To some extent, such intergenerational transfers of wealth occur in many areas of utility ratemaking. Nonetheless, most regulatory commissions attempt to minimize these transfers by apportioning the burden of the costs of a specific year's energy services on those who use those services. Deferral or balancing accounts can help facilitate the appropriate distribution of such costs.[17]

An example of one way that a deferral account could be utilized would be when a utility and commission agree to projected estimates of:

1. the number of allowances that are likely to be generated by specific overcontrol compliance activities,
2. the annual revenue requirements of these overcontrol compliance activities, and
3. the annual future market price of allowances.

The utility could then "trend" the yearly revenue requirements so that the year-to-year profile matched that of the allowance market price projections. These trended revenue requirements would be calculated so that they had the same present value as the actual standard revenue requirements. If the compliance activities were expected to be cost-effective, the trended revenue requirements would always be less than the allowance price in each year. The utility would be allowed to recover the trended revenue requirements in each year's rates. The difference between the actual and trended revenue requirements would be placed in a deferred expense account, and presumably, allowed to earn a rate of return. The gains from allowance sales would be calculated as the difference between the sales revenue and the trended revenue requirements. Therefore, allowances generated in each year could always be sold at a profit,

[17] However, not all state commissions have the authority to establish such accounts.

provided they were generated from cost-effective overcontrol activities. Those gains could be flowed through to the ratepayers or divided between ratepayers and stockholders. The projections of compliance costs and allowance prices could be revisited periodically and appropriate adjustments made to ensure that a project's deferred expense balance became zero by the end of the project.

Mismatch between Rate-of-Return and Market-Based Regulation

If a utility's surplus allowances are not valued at zero cost, a commission may want to assign a value to them that matches their costs of production as described above. Such production costs could be based on the conventional revenue-requirements approach used in rate-of-return regulation. However, there is a fundamental mismatch between rate-of-return regulation and the realities of a market-based environmental system. Using the revenue-requirements approach could potentially distort a utility's motivations. Since conventional regulatory practices cause capital-intensive projects to be most expensive in their early years, the cost basis for an excess allowance generated from a scrubber may be considerably higher in the scrubber's first year than later on. This declining cost trend may be in contrast to the trend of allowance prices. Many believe that allowance prices will increase over time, as emissions constraints tighten in phase II and as load growth and new plant construction in the next century increase the demand for a fixed supply of allowances. This mismatch between revenue requirements and allowance price trends could discourage utilities from selling allowances even though fundamental economics might justify it. A utility may fear that its commission, in reviewing an allowance transaction and the associated costs incurred to produce the surplus allowances, may consider the transaction to be imprudent if the costs exceed the revenues. Unfortunately, this may discourage utilities from selling their surplus allowances until prices catch up with the cost basis of the inventoried allowances. As will be shown in Chapter 5, such banking is not cost-effective. It is merely a distortion caused by disincentives from inappropriate ratemaking and accounting procedures.

As an example of the mismatch between a market-based system and the traditional revenue-requirements approach, assume that an overcontrol compliance option entailed a single, one-time capital expenditure of $58 million.[18] The option has no operating costs but is expected to reduce emissions by 20,000 tons a year for twenty years. Figure 4-1 below depicts a stacked-bar chart that represents the annual revenue requirements for this compliance option. The revenue requirements comprise depreciation, the return earned on the project's remaining balance in each year, and the taxes on the equity return. The capital-intensive nature of the project leads to declining revenue requirements over time.

The actual dollars-per-ton cost for the compliance option for each year is displayed in Figure 4-2. The value starts at approximately $525 a ton in 1995 and drops to $160 a ton by the end of the twenty years. The levelized cost for the compliance option is $400 a ton; this is the levelized value that has the same present value over the twenty-year period as the stream of actual costs.

Figure 4-3 contrasts the compliance option's declining annual dollars-per-ton revenue requirements with an allowance price forecast that starts at $380 per allowance and escalates at 4 percent per year through 2015.[19]

Under a traditional revenue-requirements approach, the sale of allowances generated/mined by the option will result in losses for the first four years. These initial losses will be more than compensated for by the sizable projected gains that are forecasted for the later years. Considering the long-term benefits, the project's net

[18] It will also be assumed that this is the utility's cheapest option; therefore, the option's marginal and average dollar-per-ton costs are the same since there is no cheaper alternative to serve as the basis for a marginal cost calculation.

[19] This translates into a levelized allowance price of $500 per allowance.

Fig. 4-1. Revenue requirements for a capital-intensive project.

Fig. 4-2. Levelized revenue requirements per ton.

Fig. 4-3. Rate-of-return regulation and allowance market price.

present value will be substantial. However, this value will be diminished if the utility banks the surplus allowances because it fears adverse regulatory and accounting treatment of sales during the early years. Regulators must be careful not to create disincentives for selling allowances. Potentially, some alternative regulatory treatments can be devised that would make a utility more apt to pursue profitable ventures in the allowance market and would ensure that each year's ratepayers and stockholders were properly compensated through time for any risks they were forced to bear. One possibility would be establishing a deferral or balancing account in which some portion of the early compliance costs would be deferred until later years.[20] Effectively, the cost basis of banked allowances could be levelized over the life of the overcontrol compliance activity or even "trended" to match allowance market price projections. In either case, if the compliance project's annual revenue requirements exceeded that year's allowable cost recovery basis, the difference could be placed in a balancing account, which would presumably earn a return. Therefore, ratepayers would not bear the full booked cost of the project in such years. In later years, the allowable cost recovery would exceed the annual revenue requirements, and the balancing account would be drawn down. In these years, ratepayers would pay more than under traditional revenue requirements. By the end of the project, the ratepayers would have fully compensated the utility's stockholders for the investment, and the balancing account would have a zero balance. Similar arrangements were used in "phase-in" proceedings during the 1980s to mitigate the rate shock associated with placing large, expensive nuclear power plants in rate base.

Summary

Utility regulators face new challenges in addressing ratemaking issues under the CAAA. Given that this legislation has introduced a new, marketable asset for utilities, commissions may need to consider new regulatory approaches to promote efficient use of this asset. This may be necessary because of the peculiar nature of allowances. On the one hand, they have been given to

[20] However, in some states, the commission lacks the authority to set up deferral or balancing accounts.

affected utilities at no charge, and on the other hand, they have a marketable value. As is discussed in this chapter and the next, conventional regulatory treatments may not be appropriate for compliance activities and allowance management.

In determining a ratemaking treatment for compliance costs and allowances, regulators are likely to find that the two worlds of traditional rate-of-return regulation and market-based environmental regulation are fundamentally mismatched and may require new regulatory approaches. These approaches should seek to alleviate disincentives that might discourage utilities from pursuing cost-effective allowance transactions. One such approach may be the establishment of deferral or balancing accounts that would allow the recovery of the costs of generating excess allowances to more closely match projected allowance price trends. This also will be discussed in more detail in the next chapter.

The next three chapters explore different regulatory treatments for allowances and compliance-related activities. These regulatory treatments are defined in terms of the treatment of compliance costs, allocated allowances, allowance inventory valuation, allowance purchase costs, and gains or losses on sales. The following chapters analyze the potential biases that utility regulators may introduce by selecting certain treatments.

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CHAPTER 5

TRADITIONAL REGULATORY APPROACH

This chapter examines a traditional approach to the recovery of compliance costs and identifies some of its shortcomings as well as its beneficial attributes. Since the Clean Air Act Amendments of 1990's (CAAA) market-based approach has introduced a new system for environmental regulation, the determination of what constitutes a "traditional approach" is problematic. Since the national sulfur dioxide (SO_2) allowance market is entirely new, commissions have never confronted the particular challenges and opportunities they now face. Therefore, there is no clear existing or traditional approach. The intent of the analysis in this report is to identify and compare possible regulatory treatments and to determine how various approaches may bias utility decisionmaking. The establishment of a conceptual baseline will be helpful in performing this comparative analysis. The traditional approach that is identified here will serve as this conceptual baseline. It will be shown that such an approach may not provide a utility with the necessary incentives to pursue a least-cost compliance strategy.

As mentioned above, it is difficult to describe a traditional ratemaking approach for utility compliance activities because the CAAA has presented utilities and regulators with new challenges. The approach described in Table 5-1, however, will be designated as traditional ratemaking for the purpose of this report's analysis.

The traditional approach may not encourage a utility to select the best (that is, least cost) compliance strategy. For instance, it may not motivate a utility to explore cost-saving or profit-making opportunities in the newly evolving market for emissions allowances. Many feel that potential allowance sellers (that is, those utilities with relatively low control costs) may not be motivated to overcontrol (when it is economical to do so) and produce profitable allowances if all of the gains from such activities would go toward reducing their customer rates. Not only are there no benefits for utility stockholders in such an arrangement, but it could carry considerable risks, as well. If

TABLE 5-1 COST RECOVERY FRAMEWORK: TRADITIONAL REGULATORY APPROACH	
Compliance Costs	Capital Expenditures: All prudent capital expenditures will be placed in rate base; the undepreciated balance will be allowed to earn a fair rate of return. Expenses: All prudent operating expenses will be recovered in rates in the year they are incurred.
Allocated Allowances	All allocated allowances, including bonus allowances, will be placed in the utility's inventory based on historical (that is, zero) cost.
Allowance Inventory	Inventory Valuation: The Weighted-Average-Cost method will be used for inventory valuation (that is, FERC's method). Therefore, purchased allowances will be "mixed" with allocated allowances in determining the cost of allowances withdrawn each year to cover the utility's emissions and allowance sales. Return on Inventory: The utility will be allowed to earn a return on the inventory balance.
Purchased Allowances	All purchased allowances will be placed in the utility's allowance inventory at their purchase cost (under an historical cost basis).
Sold Allowances	All gains and losses from allowance sales will be flowed through to the utility's ratepayers in the year of the transaction.

allowance prices did not end up being as high as the utility had anticipated, the project could lose money and the utility might be saddled with cost disallowances. This perceived asymmetric payoff for such projects is likely to cause potential allowance sellers to forego cost-effective opportunities in the allowance market; instead, these utilities will merely reduce their emissions to their stipulated allowance levels.

Another problem with the traditional approach is that it may lead to situations in which utilities overcontrol their emissions when they should not. For example, assume that a utility is contemplating the construction of a scrubber for one of its coal-fired units. The scrubber will reduce the utility's total emissions to a level below its allowance allocation, thereby freeing up allowances for sale. Assume that the utility is allowed to place the entire scrubber investment in rate base. If the excess allowances that accumulate in inventory are valued at zero cost (as has been suggested in FERC's accounting rulemaking), the utility will be able to sell the allowances at any price and record a gain. This does not mean that the project is cost-effective. In fact, the project could represent a considerable loss. The scrubber may create allowances at a very high incremental cost. If the cost basis for these allowances better reflected the true costs of generating the excess allowances, it would be more apparent from the beginning whether a project was cost-effective or not.

Selling versus Banking--An Example

To understand such circumstances and the possible outcomes or biases that a traditional regulatory approach could introduce, consider the following numerical example. This example uses the assumptions outlined above as to the regulatory treatment of compliance activities, allowance transactions, and allowance inventory valuation.

Assume that a utility faced the projections of uncontrolled emissions and allocated allowances, illustrated in Table 5-2, and had decided to install a scrubber.

Assume also that the utility did not foresee an internal need for the surplus allowances that it was generating and was therefore amenable to the sale of these

TABLE 5-2

SCRUBBING UTILITY ASSUMPTIONS

Circumstances	**1995**	**1996**	**1997**
Uncontrolled Utility Emissions: (tons of SO_2/year)	170,000	170,000	170,000
Expected Reductions from Scrubber: (tons of SO_2/year)	70,000	70,000	70,000
Allocated Allowances: (allowances/year)	120,000	120,000	120,000
Allowance Prices: ($/allowance)	$300	$312	$325
Discount Rate: 10%			
Therefore:			
Controlled Utility Emissions: (tons of SO_2/year)	100,000	100,000	100,000
Surplus Allowances: (allowances/year)	20,000	20,000	20,000

allowances. It could sell 20,000 allowances during each of the three years or it could bank the allowances and sell them in future years. In fact, the allowances could actually be sold at any time.[1]

If the utility chose to sell the allowances in each year they were generated, the traditional regulatory approach would result in what is shown in Table 5-3.

TABLE 5-3

SCRUBBING UTILITY SELLS EXCESS ALLOWANCES
IN SAME YEAR (TRADITIONAL APPROACH)

Circumstances	**1995**	**1996**	**1997**
Allowances Sold:	20,000	20,000	20,000
End-of-Year Allowance Inventory:	0	0	0
Value of Inventory:	$0	$0	$0
Allowance Sales Revenues ($000):	$6,000	$6,240	$6,500
Present Value of Incremental Earnings:	$0		
Present Value of Incremental Revenue Requirements ($000):	-$17,045		

[1] Indeed, the utility could sell all 60,000 allowances in 1995 (or even 1994) if it chose to.

The two present value statistics shown at the bottom of the chart reflect the incremental impacts on the utility's stockholders and its ratepayers. The first statistic is the present value of incremental earnings and shows, in a discounted sense, the expected increase in the utility's earnings that would result under traditional regulation, from the sale of 20,000 allowances in each of the three years. Since all proceeds from allowance sales are to be flowed through to the utility's ratepayers, the sale of allowances will not affect a utility's earnings. The second statistic shows the present value of incremental revenue requirements. Because the utility's ratepayers are the recipients of the allowance revenues, the sale of allowances will reduce the utility's revenue requirements. The analysis assumes that the revenues from the sale would be flowed through to the ratepayers through a reduction in the utility's annual operating expenses (for example, a reduction in a fuel adjustment clause).[2] In a present value sense, the sale of allowances in each of the three years can be expected to reduce revenue requirements by over $17 million. Both of the statistics are calculated relative to a situation in which the utility did not sell the allowances at all. This example ignores test-year and other rate-setting issues in the interest of simplicity and clarity. However, the example's general conclusions would not be changed by the incorporation of these other ratemaking complications.

If the utility chose to bank the allowances and sell all 60,000 in 1997, the earnings and revenue requirement circumstances would occur as shown in Table 5-4.

The present value of incremental revenue requirements is negative in both scenarios, reflecting the benefits that ratepayers would realize from the gains from the allowance transactions regardless of the timing of those sales. However, the actual benefits to the utility's ratepayers of the banking of the allowances are less (by

[2] Instead of flowing the gains through to the ratepayers through an adjustment clause, a commission may order that such gains be used to reduce the utility's rate base. The affects on utility behavior and consumer welfare are different for each of these regulatory options, however.

TABLE 5-4 SCRUBBING UTILITY BANKS EXCESS ALLOWANCES FOR TWO YEARS (TRADITIONAL APPROACH)			
Circumstances	**1995**	**1996**	**1997**
Allowances Sold:	0	0	60,000
End-of-Year Allowance Inventory:	20,000	40,000	0
Value of Inventory:	$0	$0	$0
Allowance Sales Revenues ($000):	$0	$0	$19,500
Present Value of Incremental Earnings:	$0		
Present Value of Incremental Revenue Requirements ($000):	-$16,116		

$929,000)[3] since the present value of the reduced revenue requirements is less under the second scenario than under the first. From the stockholders' perspective, though, the utility should be indifferent. Since the allowances are valued at zero cost, the inventory balance remains at zero regardless of whether the allowances are sold or banked. Therefore, no additional earnings are generated under either case. Effectively, the utility has no financial incentive to manage its inventory of allowances cost-effectively.

[3] $929,000 = $17,045,000 - $16,116,000.

The rule of thumb for cost-effective inventory management is that an inventoried good should be sold unless:

1. the firm needs the good in inventory as security against supply interruptions, or
2. the firm believes that the price of the good will rise faster than the firm's cost of capital.

In the context of allowances, the first condition refers to the need for a utility to hold an allowance inventory that exceeds the utility's projected emissions. If a smoothly-functioning allowance market develops, such a precautionary measure will be largely unnecessary. With a market in place, if a utility finds that it needs additional allowances because of an unexpected increase in emissions, it will be able to purchase them. However, a utility may not feel 100 percent confident that the market will always be able to fulfill the utility's needs. Therefore, some finite level of surplus inventory may be justified to guard against the possibility that the market will not be able to supply additional allowances when the utility needs them. The inventory level of this cushion will depend on the utility's operating circumstances and its aversion to risk.

The second condition of cost-effective inventory management deals with speculation and price expectations. If a utility believes that allowance prices will rise significantly in the future, it may justify banking current allowances for future sale or future consumption. However, to make such a strategy profitable, the percentage price rise must exceed the utility's cost of capital. It is this requirement that determined the results of the numeric example above. In the example, the expected allowance price increase was approximately 4 percent. However, the utility's cost of capital, which was referred to in the example as the discount rate, was 10 percent. In such a case, the utility's ratepayers are better off if the utility liquidates its inventory and generates cash as soon as possible. That cash can be reinvested at a higher rate of return (that is, the discount rate) than the rate at which the inventory value is increasing (that is, the allowance price increase). Under traditional regulation, this return would most likely be flowed through to ratepayers in the year it is realized and would not be available for reinvestment by the utility (as an unregulated firm could do). However, the point remains that in this example, it is still in the best interest of ratepayers to sell the allowances and that the traditional approach is unlikely to lead to this beneficial result.

Utility regulators will have to decide whether or not they want the utility to speculate on future allowance prices, particularly if only the ratepayers' money is at risk. Effectively, any utility that banks allowances (above a level of inventory that can be justified as a hedge against lack of supply in the market) is automatically speculating in the market, whether it intends to or not. There are two price-related rationales or motivations for banking. First, a utility may feel that allowance prices are currently depressed and are bound to go much higher in the future. Thus, the utility would be inclined to hold onto any current surplus allowances in order to reap the substantial gains from sales in the future. Second, under the same price expectations, a potential selling utility might worry that future circumstances could necessitate the purchase of allowances, at high prices. Therefore, it might choose to bank its current surpluses rather than sell them at currently low prices. Both arguments assume that current prices are wrong, that is, they are not accurately reflecting future market conditions. A utility that justifies banking allowances based on either of these arguments essentially believes that it is smarter than the market. If the expectation that prices will be high in the future is widespread, it will drive up current prices. After all, if much higher prices were anticipated in the future, sellers would be foolish to negotiate deals at current, low prices. Instead, rational sellers would increase their current asking price.

If a utility believes that current allowance prices are too low, it can speculate on the price by banking its surplus allowances, or buying more. Such speculation can be highly profitable--if one guesses correctly and beats the market. However, the opposite is also true. The banking of allowances could prove to be rather costly. In the example above, the banking of allowances cost the utility's ratepayers almost $1 million in present value terms. In the event that future prices were to drop substantially,[4] the losses from a banking strategy would be considerable. For example, if allowance prices in the above example suddenly dropped to $200 per allowance in 1997, the sales revenue would only be $12 million, as is shown in the numeric example in Table 5-5.

Under a selling-every-year scenario, revenue requirements would be reduced by almost

[4] As could happen if stringent carbon dioxide (CO_2) legislation is passed.

$15 million. The difference between the two cases shows that the utility's ratepayers would lose over $5 million if the utility delayed selling its allowances until 1997, as shown in Table 5-6.

TABLE 5-5

SCRUBBING UTILITY BANKS ALLOWANCES FOR TWO YEARS, THEN SELLS WHEN PRICE DROPS (TRADITIONAL APPROACH)

Circumstances	**1995**	**1996**	**1997**
Allowances Sold:	0	0	60,000
Allowance Prices: ($/allowance)	$300	$312	$200
Allowance Inventory:	20,000	40,000	0
Value of Inventory:	$0	$0	$0
Allowance Sales Revenues ($000):	$0	$0	$12,000
Present Value of Incremental Earnings:		$0	
Present Value of Incremental Revenue Requirements ($000):		-$9,917	

TABLE 5-6

SCRUBBING UTILITY SELLS ALLOWANCES EACH YEAR
WITH PRICE DROP IN YEAR THREE
(TRADITIONAL APPROACH)

Circumstances	**1995**	**1996**	**1997**
Allowances Sold:	20,000	20,000	20,000
Allowance Prices: ($/allowance)	$300	$312	$200
Allowance Inventory:	0	0	0
Value of Inventory:	$0	$0	$0
Allowance Sales Revenues ($000):	$6,000	$6,240	$4,000
Present Value of Incremental Earnings:	$0		
Present Value of Incremental Revenue Requirements ($000):	-$14,979		

Considering that some utilities anticipate banking much larger numbers of allowances, the costs of "overbanking" could represent a significant burden to ratepayers. Under traditional regulation, utilities have little incentive to manage their allowance inventories appropriately. Commissions will have to be aware of the biases that they could introduce or reinforce if the interests of utility ratepayers and stockholders are not aligned in the wise management of these inventories.

Another Inventory Distortion: Swapping Allowances

As mentioned earlier, under traditional regulation, a utility may have an incentive to swap its allocated allowances with purchased allowances in order to give its allowance inventory a nonzero value. This way, the utility could earn a rate of return on the inventory balance. Such activities would make the utility's ratepayers even worse off, as shown in Table 5-7.

Using the same assumptions as in the original example (that is, with rising allowance prices over the three years), the utility's sale/buy-back strategy would result in the following inventory valuation under a traditional regulatory approach. Again, the utility is assumed to sell its entire accumulated inventory in 1997.

In this case, the ratepayers are even worse off than in the previous situations since the benefits from the allowance sales are reduced by the utility's allowed return on the inventory balance. The yearly sale/buy-back strategy results in a neutral cash flow arrangement, provided that the selling and buying prices are the same. However, since purchased allowances will be included in inventory at their acquisition cost, this strategy will convert the inventory into a market-valued inventory. If the utility is allowed to earn a return on the inventory, this will bias the utility toward the accumulation of allowances. The longer the utility holds onto the surplus allowances, the more earnings the stockholders will be able to reap from the return on inventory. Since this return is paid by the ratepayers, it boosts the revenue requirements (and thereby reduces the amount that revenue requirements would be lowered by the allowance revenues). Thus, compared to the earlier, similar scenario in which allowance swapping does not occur (see Table 5-4), the ratepayers are worse off by the $3.262 million earned on the inventory.[5]

[5] $3.262 million = $16.116 million - $12.854 million.

TABLE 5-7

SALE/BUY-BACK STRATEGY
UNDER TRADITIONAL APPROACH

Circumstances	1995	1996	1997
Allowances Sold:	20,000	20,000	20,000
Allowances Purchased:	20,000	20,000	20,000
End-of-Year Allowance Inventory:	20,000	40,000	60,000
Value of Inventory ($000): (prior to final sale)	$6,000	$12,240	$18,740
Annual Return on Inventory[1] ($000):	$600	$1,224	$1,874
Value of Inventory ($000): (after final sale)	$6,000	$12,240	$0
Allowance Sales Revenues ($000):	$0	$0	$19,500
Present Value of Incremental Earnings ($000):	$3,262		
Present Value of Incremental Revenue Requirements ($000):	-$12,854		

[1] Assuming an authorized rate of return of 10 percent.

In all of the above examples, it is important to note that the underlying *costs* of the utility's compliance activities are not reflected in the inventory value of allowances. Hence, it is never clearly determined whether or not the 20,000 allowances produced each year have been produced at a profit. *All of the allowances appear to be sold for a gain, because they all have a zero cost basis*. Meanwhile, all prudent compliance costs are recovered regardless of the price the utility is able to get for its surplus allowances. Inherently, the traditional approach does not provide any incentive for the utility to pursue cost-effective (that is, profitable) allowance transactions. The relative reductions in revenue requirements in the above examples do not consider that the utility's ratepayers may be paying for a scrubber that has a cost that far exceeds the price at which the surplus allowances are being sold. If the utility does not implement a cost-effective compliance strategy, the traditional regulatory approach will saddle the ratepayers with the losses. These losses will be hidden by the inappropriate, zero cost basis of the initially allocated allowances.

The Buying Utility's Biases

The above examples have focused on the biases that the traditional regulatory approach may introduce for those utilities that have low compliance costs and would therefore be *sellers* in the allowance market. The traditional approach also introduces biases for those utilities that have high compliance costs and should be *buyers* in the allowance market. As was discussed in the context of allowance sellers, the perception of asymmetric payoffs may discourage potential allowance buyers from using the allowance market. If the savings from cost-effective purchases are used to reduce customer rates, there are no benefits for a utility's stockholders from good decisions. Reliance on the allowance market carries some risks, however, and concerns about the regulatory outcome of bad decisions may keep some utilities out of the allowance market. Since many compliance activities require advance planning, utilities may have to decide whether or not to implement their own compliance activities well before the price of allowances develops in the emerging allowance market. Considering the risks of betting on future allowance prices, utilities may opt for implementing their own compliance activities. However, allowance prices could end up rather low, making these other compliance activities economically unattractive. These price risks, however, will be avoidable if an active forward or futures market develops. If that happens, a utility will be able to lock in allowance prices at the time it decides to forego its own compliance activities.

Summary

Pursuing a traditional regulatory approach for compliance ratemaking has some benefits and drawbacks. In some ways, conventional approaches could provide for simpler and more straightforward calculations of allowance values and allowed returns. However, these simpler processes are likely to cause significant distortions in the incentives for utilities to pursue least-cost compliance strategies.

First, valuing the allowances received from the U.S. Environmental Protection Agency at zero cost does not accurately reflect the value of these assets. Consequently, utilities are not given the appropriate ratemaking "price signals" to manage these assets in a cost-effective manner. If utilities are allowed to earn a return on their allowance inventories, this mismatch between the value of allocated allowances and that of purchased allowances may lead utilities to pursue selling and buying strategies that do little more than turn over the inventory (and thereby increase its accounting value, but not its real value).

Second, unless utilities are provided with some financial incentives to pursue cost-effective allowance sales, the traditional regulatory approach is likely to result in excessive allowance banking. This banking will only be justified if allowance prices are expected to escalate faster than a utility's cost of capital or if the utility fears that sufficient numbers of allowances will not be available in the future. Otherwise, selling excess allowances from year to year will be more beneficial to ratepayers than banking.

Even when clearer allowance price signals develop, reliance on the market will involve some substantial risks. If commissions want to ensure that utilities adopt least-cost compliance plans that incorporate cost-effective allowance management, the utilities will need to be compensated for allowance market risks. Two ratemaking approaches that would provide utilities with financial incentives for bearing these risks are discussed in the next two chapters.

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CHAPTER 6

MARKET-BASED APPROACH

It can be seen from the previous chapter that the traditional regulatory approach does not provide incentives for utilities to search for beneficial opportunities in the allowance market. In fact, the traditional approach is likely to introduce biases that may cause utilities to pursue inappropriate strategies.

As an alternative to the traditional ratemaking approach, state regulatory commissions might consider incentive ratemaking approaches that may be more effective in promoting least-cost compliance planning. This might be accomplished by providing utility stockholders with some of the gains from the cost-effective use of allowances. Such arrangements have been proposed in earlier NRRI reports[1] and might be called the "market-based" approach. There are several variations of this approach that a commission could implement. What follows is merely one example of a market-based mechanism. Such a ratemaking treatment might entail the following five steps:

1. **Establishment of Benchmark Price:** Each year, the commission would establish a benchmark allowance price based on the current market price or market index.

2. **End-of-Year Filing of Compliance Information:** At the end of the year, the utility would report:
   - the compliance activities that it had undertaken,
   - the cost of these activities,

[1] Kenneth Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, 1992), Chapter 9; and Kenneth Rose, "Regulatory Treatment of Allowances and Compliance Cost: What's Good for Ratepayers, Utilities, and the Allowance Market?" in Kenneth Rose and Robert E. Burns, eds., *Regulatory Policy Issues and the Clean Air Act: Issues and Papers from the State Implementation Workshops* (Columbus, OH: The National Regulatory Research Institute, 1993), 117-40.

- its estimated uncontrolled emissions,[2]
- its mandated emissions reduction requirement,[3]
- its actual emissions,
- its allowance status (that is, the number of allowances generated, sold, banked, or purchased during the year), and
- the price of any allowance transactions that it negotiated.

3. **Calculation of Compliance Costs:** Each activity's dollars-per-ton marginal compliance costs would be calculated, and the activities would be ranked (from least cost to highest cost as described in Chapter 3).

4. **Determination of Allowable Cost Recovery:** The utility would be allowed to recover the costs of all compliance activities that had costs below the benchmark price.

5. **Sharing of Gains and Savings:** In the case of a utility that generated excess allowances, the compliance options that were responsible for the overcontrol of the utility's emissions would be identified. Presumably, the commission would attribute the overcontrol to the most expensive compliance activities, reserving the least expensive activities for the ratepayers. For the overcontrol options, the utility would

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[2] A utility's estimated uncontrolled emissions would represent an estimate of the emissions that would have occurred if the utility had not implemented any of its compliance options. It is not an observable value. Instead, it would involve running a computer simulation of the utility system's operations with the year's actual loads and actual unit availabilities. Units that had been fuel-switched would be assumed to burn their original fuel. Scrubbed units would be assumed to operate without the scrubbers.

[3] The utility's "mandated emissions reduction requirement" is discussed in Chapter 2 and would be calculated as the difference between the utility's estimated uncontrolled emissions and the number of initially allocated allowances. This represents the reduction that the utility would have to achieve to be in neither a surplus or deficit allowance position at the end of the year. Based on the utility's projections, if it achieved its mandated emissions reduction requirement, the utility would not generate allowances for sale, nor would it be required to purchase allowances.

receive (or lose)[4] a predefined percentage of the difference between the overcontrol options' dollars-per-ton marginal costs and the benchmark or market price, as discussed above.

In the case of a buyer, a utility that pursued any compliance activities that had costs in excess of the benchmark price would not be permitted full cost recovery for those activities. Instead, the utility would only be allowed to recover the benchmark price plus the ratepayers' portion of a predefined percentage split of the difference between the utility's compliance costs and the benchmark price. Therefore, the utility would suffer a "disallowance" equal to the stockholders' portion of the split arrangement. In the event that the utility purchased allowances for current year consumption, the utility would receive a percentage of the difference that the price of the allowances was below the benchmark price.[5]

Gains and losses (that is, the difference between the benchmark and actual marginal cost) will be split between a utility's ratepayers and stockholders based on a predetermined percentage. For example, a commission could authorize a 90 percent/10 percent split, in which 90 percent of

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[4] The sharing mechanism would be symmetrical; therefore, if the options' marginal dollars-per-ton cost exceeded the benchmark price, the utility would share in the loss.

[5] This market-based approach can be expressed as:

$$E_i = (P - MC_i)S$$

where:

E_i	=	utility earnings for a given ton (i) of SO_2 reduced or allowance purchased
P	=	market price of allowances
MC_i	=	utility's marginal SO_2 control cost for ton i or allowance cost, and
S	=	utility share of gain (when $P > MC_i$) or loss (when $P < MC_i$)

Ratepayer gain or loss would be:

$$R = (P - MC_i)(1 - S)$$

Calculation of the terms are explained by examples in this chapter.

the gains from an allowance sale would go to the ratepayers (in the form of a rate reduction) while 10 percent would be kept by the utility's stockholders. A commission would want to establish a reasonable percentage distribution so that the earnings incentive will be large enough to motivate the utility to pursue cost-effective allowance transactions yet not so large as to unnecessarily compromise the ratepayers' entitlement to a portion of the benefits.

In the case of allowance sales, the utility's highest cost compliance activities will serve as the basis for the sales. Whether a sale results in a gain or loss will depend on whether its price is greater or less than the dollars-per-ton cost of the underlying compliance activities that made it possible. Regardless of whether this difference constitutes a gain or a loss, it will be divided between the utility's ratepayers and stockholders based on the predetermined percentage set by the commission.

In the case of allowance purchases, the purchases will be compared against the internal utility compliance activities and the purchase price compared with the benchmark. Positive savings will be generated if the purchase price of the allowances is less than the benchmark. A loss would occur if the allowance price was higher. In either case, the difference between the costs will be divided between the ratepayers and stockholders based on the commission-approved percentage.

Commissions could implement several variations of the five-step approach described above. The end-of-year approach that is the basis of this chapter's numerical examples could be accommodated within a framework of historical test years or future test years, fuel adjustment clauses, or no fuel adjustment clauses--whatever system a particular commission currently uses. For this example, it will be assumed that an historical test year framework is used and that there is no fuel adjustment clause. Therefore, for instance, 1995 costs deemed appropriate during the end-of-year filing will be recovered in 1996. For the purpose of developing numerical examples, the assumptions outlined in Table 6-1 will be used.

As displayed in Table 6-1, several of the five cost-recovery categories involve different regulatory treatments than was described under the traditional approach. For

TABLE 6-1 NUMERICAL EXAMPLE ASSUMPTIONS--MARKET-BASED APPROACH	
Compliance Costs	Capital Expenditures: Assets are not ratebased. Expenses: Operating expenses are recovered based on the market price of allowances in the year following the one in which they are incurred.
Allocated Allowances	Not necessary to place a value on utility's allocated allowances.
Allowance Inventory	Inventory Valuation: A commission may wish to establish a different inventory methodology for purchased, sold, and end-of-year surplus allowances. Return on Inventory: Inventory is not ratebased.
Purchased Allowances	All purchased allowances will be placed in a temporary allowance inventory at their purchase cost. In the year that purchased allowances are consumed, the savings and losses will be determined and will be split between the utility's ratepayers and stockholders.
Sold Allowances	The gains and losses from allowance sales will be determined and split between the utility's ratepayers and stockholders in the year of the transaction.

the valuation of allocated allowances, the excess allowance accounting perspective will be used. From this point of view, the value of a utility's total allocation of allowances becomes a moot point. Allowances are assumed not to have a discernable value until they are generated. Therefore, this value will not be determined until the end of the year, when the exact number of surplus allowances is known and the historical costs associated with these allowances can be determined.

The proposed market-based approach can be applied to situations involving multiple current-year purchases and sales. However, for the sake of simplicity in describing the proposed approach, the two examples discussed below examine utilities that are either purchasers or sellers[6] of allowances in any given year--but not both.

A Selling Utility--An Example

To illustrate the proposed market-based approach for a potential allowance seller, assume that a particular commission set a utility's benchmark price at $300 for 1995. Also assume that the utility has three fuel-switching options it is considering for reducing its sulfur dioxide (SO_2) emissions. Table 6-2 lists a set of assumptions surrounding the utility's situation in 1995. The first column of numbers reflects the projected values at the beginning of 1995. In conjunction with the benchmark price, these are the projections upon which the utility will base its compliance decision for 1995. The second column of numbers is the actual known results at the end of 1995. These are the numbers that will affect the utility's recovery of costs and its sharing in the gains or losses from its compliance decisions.

As indicated in Table 6-2 and displayed graphically in Figure 6-1, the utility expects the fuel-switching options at BIGCOAL 1, 2, and 3 to have annual costs of $250, $280, and $320 per ton of SO_2 removed, respectively. With a benchmark price of $300, the utility can justify pursuing the first two fuel-switching options (at BIGCOAL 1 and 2). Since it appears that the fuel-switching option at BIGCOAL 3 will be more expensive than the benchmark price, the utility will not pursue that option.

The utility's mandated emissions reduction target is 50,000 tons and can be met with the first option alone. Thus, pursuing the second option as well should free up surplus allowances at a cost that is below the benchmark price. By fuel switching at

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[6] The term seller here merely means a utility that is generating surplus allowances. These allowances may be sold in the allowance market or "sold" to future ratepayers (that is, banked for internal use).

TABLE 6-2

SELLING UTILITY ASSUMPTIONS

Circumstances	1995-Projected	1995-Actual
Uncontrolled Utility Emissions: (tons of SO_2/year)	170,000	175,000
Allocated Allowances: (allowances/year)	120,000	120,000
Mandated Emissions Reduction Target: (tons of SO_2/year)	50,000	55,000
Fuel Switching at BIGCOAL 1		
Reduced Emissions (tons of SO_2/year):	50,000	60,000
Total Cost ($M):	$12·5	$15·6
Annual Incremental $/Ton Cost:	$250	$260
Fuel Switching at BIGCOAL 2		
Reduced Emissions (tons of SO_2/year):	30,000	20,000
Total Cost ($M):	$8·4	$5·4
Annual Incremental $/Ton Cost:	$280	$270
Fuel Switching at BIGCOAL 3		
Reduced Emissions (tons of SO_2/year):	60,000	0
Total Cost ($M):	$19·2	$0
Annual Incremental $/Ton Cost:	$320[1]	--
Final Utility Emissions: (tons of SO_2/year)	90,000	95,000
Surplus Allowances:	30,000	25,000
Split Percentage: (Ratepayer/Stockholder)	90%/10%	

[1] Since this compliance option's projected cost is greater than the benchmark price, the utility will not implement the option.

Fig. 6-1. Example of overcontrolling utility's compliance costs, emission requirement, and benchmark price.

BIGCOAL 1 and 2, the utility expects to reduce its emissions by 80,000 tons (50,000 tons + 30,000 tons) at a cost of $20.9 million ($12.5 million + $8.4 million). Therefore, its total projected emissions will drop from 170,000 tons to 90,000 tons. Since the utility is allocated 120,000 allowances to cover its 1995 emissions, the two fuel-switching strategies are projected to free up 30,000 allowances.

At the end of 1995, the actual results are known (and are displayed in the second column of Table 6-2). The utility would file that its actual operations had resulted in annual emissions of 95,000 tons, leaving it with 25,000 surplus allowances. The utility would also report to the commission what the utility's total emissions would have been at each of its affected sources had it not pursued the fuel-switching options it had selected. In addition, the utility would report the annual *incremental* costs that had been incurred because of its fuel-switching options. All of this information is required to calculate the annual dollars-per-ton costs for each of the compliance options. The estimation of uncontrolled emissions and incremental costs may be somewhat difficult, however, given the interrelationship between compliance activities. This is discussed further in the section below on advantages and disadvantages. For the sake of this example, though, it will be assumed that the utility was able to estimate that its uncontrolled emissions would have been 175,000 tons, and that fuel switching at BIGCOAL 1 and 2 was responsible for emissions reductions of 60,000 tons and 20,000 tons, respectively. These reductions therefore resulted in total emissions of 95,000 tons. In the case of costs, the BIGCOAL 1 fuel-switching option was found to have had incremental costs of $15.6 million, yielding an annual cost of $260 a ton:

$$\$260 \text{ a ton} = \frac{\$15.6 \text{ million}}{60{,}000 \text{ tons}}$$

The $15.6 million represents the fuel-switching option's *incremental* costs. This amount is the *premium* that was paid for the low-sulfur coal that was burned at the unit and had resulted in the reduction of BIGCOAL 1's 1995 emissions by 60,000 tons. Therefore, such a calculation will require the comparison of the price of the low-sulfur coal with the price of the original coal[7] that BIGCOAL 1 used to burn. This price differential would be multiplied by the unit's annual fuel burn. The same type of calculations would be made for BIGCOAL 2, yielding a total incremental cost of $5.4 million and an annual dollars-per-ton cost of $270 a ton. Therefore, fuel switching at BIGCOAL 1 was the cheaper of the two compliance options.

The mandated emissions reduction target represents those emissions reductions required to exactly match the utility's emissions with its allocated allowances. Presumably, since compliance with environmental regulations is part of the utility's business of supplying energy services, the utility's ratepayers would be entirely responsible for paying for this level of emissions reduction. Also, the ratepayers should only pay for the cheapest compliance options required to meet the mandated emissions reduction target. If a utility chooses to push beyond this level of emissions reduction (and free up surplus allowances for sale or later use), it should be the more expensive compliance options that are associated with "generating" the surplus allowances. Therefore, in the context of the current example, almost all of the costs of fuel switching at BIGCOAL 1 would be expensed and borne by the utility's ratepayers since this fuel-switching option entirely covered the mandated emissions reduction target of 55,000 tons and the cost is below the benchmark value set by the commission. In fact, the fuel switching at BIGCOAL 1 was responsible for 5,000 of the 25,000 surplus allowances that the utility had left over at the end of 1995. The other 20,000 allowances were freed up by the fuel-switching activities at BIGCOAL 2. Therefore, eleven-twelfths[8] of BIGCOAL 1's fuel-switching costs should be directly expensed to the utility's ratepayers. This would result in $14.3 million of the $15.6 million being immediately recovered in rates. The other $1.3 million, combined with the $5.4 million attributable to fuel switching at BIGCOAL 2, would represent the costs that had been incurred to free up

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[7] Presumably the 1995 spot price.

[8] This represents the 55,000 tons (that covers the mandated emissions reduction target) out of the total 60,000 tons.

the 25,000 surplus allowances. These costs would yield a cost basis for these allowances of $268 per allowance (again, the cost is below the benchmark value).[9]

Assume that the utility chose to sell these 25,000 allowances at a price of $300 per allowance. The results are presented in Table 6-3.

Thus, the commission would authorize the utility's 1996 rates to include $13.58 million--the $14.3 million in "direct" fuel-switching costs at BIGCOAL 1, minus the portion of the gains from the allowance sale that the ratepayers are due ($0.72 million). The rest of the fuel bill ($6.7 million)[10] would be covered by the proceeds from the allowance sale ($7.5 million). In comparison to the situation in which the utility had merely controlled its emissions to meet its mandated emissions reduction target, the ratepayers and stockholders would receive the benefits shown in Table 6-4.

TABLE 6-3

REVENUES AND GAINS FROM SALE OF ALLOWANCES

Allowance Sales Revenues	$7.5 million
Gains from Sale	$0.8 million
Ratepayer Portion of Gains (90%)	$0.72 million
Stockholder Portion of Gains (10%	$0.08 million

[1] $7.5 million = 25,000 allowances x $300 per allowance
[2] $0.8 million = 25,000 allowances x ($300 per allowance - $268 per allowance)
[3] $0.72 million = 90% x $0.8 million
[4] $0.08 million = 10% x $0.8 million

[9] $268 per allowance = ($1.3 million + $5.4 million) / 25,000 allowances.

[10] $6.7 million = $1.3 million for the remainder of BIGCOAL 1's fuel-switching costs and $5.4 million for all of BIGCOAL 2's fuel-switching costs.

TABLE 6-4 NET RATEPAYER AND STOCKHOLDER BENEFIT FROM SALE OF ALLOWANCES	
Revenue Requirements	$0.72 million less
Earnings	$0.08 million more

Thus, both the ratepayers and the stockholders would be better off in this situation.

If the utility did not sell the year's surplus allowances but banked them instead, the $6.7 million that was incurred to generate these allowances would not be immediately included in rates. Instead, this money could represent a stockholder investment and earn a return until the allowances were sold or consumed. If the allowances were sold at some point in the future, the cost recovery process would follow the same market-based procedure described above. In the year of the sale, the gains (or losses) would be split between the stockholders and the ratepayers based upon the predetermined percentage. If the allowances were consumed rather than sold, the cost of the consumed allowances would be included in rates in the year that the allowances were consumed. If the commission decided to use a weighted-average methodology for inventory valuation, the cost of each consumed allowance would be the average value of all of the allowances in inventory. In the case of the above example, if there had been no subsequent additions to the allowance inventory, the ratepayers would be charged $268 per allowance in the year the allowances were consumed.

Economically, there is an incentive for the utility to sell surplus allowances within a reasonable time. The longer a utility waits to sell, the longer it waits to realize its portion of the gain from the transaction. In a present value sense, that gain is likely to diminish the longer the utility waits. If the utility had generated very high cost allowances, such that the sale of these allowances would result in losses, the incentive is reversed. Deferring the sale of the allowances would diminish the losses in a present value sense. Also, the utility may justify its banking hoping that its apparent losses may turn into gains if it is patient enough to wait for higher future allowance prices. Under these circumstances, a utility could have very strong incentives to avoid selling its allowances. Setting reasonable benchmark prices in the first place is a way commissions can minimize this adverse incentive.

A Buying Utility--An Example

As an example of how the market-based approach would work with a utility that was an allowance purchaser, assume that all of the circumstances in the above example were the same except that the utility was only allocated 80,000 allowances and that the benchmark price was set at $275. Table 6-5 summarizes the utility's circumstances.

In this case, fuel switching at either BIGCOAL 2 or BIGCOAL 3 is more expensive than the benchmark. Therefore, the utility will not pursue those options, and will choose instead to fuel switch only at BIGCOAL 1. Since the utility's mandated emissions reduction target is 90,000 tons and BIGCOAL 1 fuel switching is only expected to achieve 50,000 tons of emissions reduction, a 40,000-ton shortfall is projected that will have to be covered with allowance purchases.

At the end of the year, the actual shortfall is a little less: 35,000 allowances. Assume that the utility purchases 35,000 allowances at a price of $270 per allowance. Since this price is below the benchmark price, a positive savings will result that will be split between the utility's ratepayers and stockholders. Given these results, the ratepayers will be responsible for:

1. the $15.6 million fuel-switching costs at BIGCOAL 1,
2. the $9.45 million allowance purchase costs,[11] and

[11] $9.45 million = 35,000 allowances x $270 per allowance.

TABLE 6-5

PURCHASING UTILITY ASSUMPTIONS

Circumstances	1995-Projected	1995-Actual
Uncontrolled Utility Emissions: (tons of SO_2/year)	170,000	175,000
Allocated Allowances: (allowances/year)	80,000	80,000
Mandated Emissions Reduction Target: (tons of SO_2/year)	90,000	95,000
Fuel Switching at BIGCOAL 1		
Reduced Emissions (tons of SO_2/year):	50,000	60,000
Total Cost ($M):	$12·5	$15·6
Annual Incremental $/Ton Cost:	$250	$260
Fuel Switching at BIGCOAL 2		
Reduced Emissions (tons of SO_2/year):	30,000	0
Total Cost ($M):	$8·4	$0
Annual Incremental $/Ton Cost:	$280	--
Fuel Switching at BIGCOAL 3		
Reduced Emissions (tons of SO_2/year):	60,000	0
Total Cost ($M):	$19·2	$0
Annual Incremental $/Ton Cost:	$320	--
Final Utility Emissions: (tons of SO_2/year)	120,000	115,000
Allowance Purchases:	40,000	35,000
Split Percentage: (Ratepayer/Stockholder)	90%/10%	

3. the $0.0175 million that represents the stockholder's portion of the savings from the allowance purchase.[12]

Because of this arrangement, the utility will have an incentive to pursue cost-effective allowance purchases and avoid implementing higher-cost internal compliance options. Based on the projections of the costs of fuel switching avoided at BIGCOAL 2 and 3, the benefits shown in Table 6-6 will accrue to the utility's ratepayers and stockholders relative to a situation in which the utility reduces its emissions to its mandated emissions reduction target. *Again, both the ratepayers and the stockholders would win in this situation.*

Although the magnitude of the savings may not seem significant in this example, the reader should be aware that real utility situations may involve considerably larger differences between internal compliance costs and allowance prices. These large differences will greatly increase the benefits of this type of incentive regulation for both the utility's stockholders and ratepayers.

Advantages and Disadvantages

The advantages of the market-based approach have been shown through quantitative examples. This type of incentive regulation could encourage utilities to pursue cost-effective compliance and allowance transactions, thereby reducing the net compliance costs that will be borne by the ratepayers. However, this ratemaking approach may have some drawbacks. First, it requires the calculation of annual dollars-per-ton costs for each of a utility's compliance activities. The costs and emissions reduction impacts of individual compliance activities may be hard to isolate. Changes in system operations and dispatch can significantly affect a utility's emissions. In fact, some form of emissions dispatch (that is, the use of cleaner, more expensive resources instead

[12] $0.0175 million = 10% x 35,000 allowances x ($275 per allowance - $270 per allowance).

TABLE 6-6 NET RATEPAYER AND STOCKHOLDER BENEFIT FROM PURCHASING ALLOWANCES	
Revenue Requirements	$0.533 million less
Earnings	$0.0175 million more

Note: Net Savings = BIGCOAL 2's costs
+ 5,000-allowance portion of BIGCOAL 3's costs
− allowance purchase costs
− stockholders' portion of savings

= $8.4M + ([5000/60000] x $19.2M) - $9.45M - $0.0175M

of high SO_2-emitting generating units) will probably be a viable, cost-effective compliance option for many utilities. This may involve a greater reliance on gas-fired generation, for instance. However, it could be difficult and time-consuming to analyze a utility's hour-by-hour operations to determine when gas-fired generation was being utilized for SO_2-reduction reasons or for transmission constraints or other operational requirements. The interrelated effects of different compliance options at different generating units can make it difficult to isolate the costs and impacts of individual compliance activities if several are implemented at the same time.

Regulators will have to be careful to ensure that these difficulties do not result in a utility filing compliance numbers that have been manipulated for the utility's gain. For example, if a utility claimed that its increased use of gas-fired resources was due to operational constraints rather than compliance objectives, it could argue that the gas costs should be passed on to ratepayers as a standard fuel cost. If, as a consequence of this increased use of gas, the utility had curtailed its emissions and generated surplus allowances, the utility might contend that these allowances had been produced at a very low cost. The lower the cost, the greater the gain in which the utility's stockholders would share when the allowances were sold. Therefore, there would be an incentive for utilities to understate the costs of compliance by shifting or hiding as many expenses as possible in the regular operations side of their business. By the same token, utilities would be inclined to overestimate their "uncontrolled" emissions upon which the compliance activities emissions reductions are based. With fuel switching, for example, one means of calculating "uncontrolled" emissions would be to multiply the affected unit's annual fuel burn (in mmBtu) by the SO_2 emissions rate of the unit's original fuel (that is, the fuel that the unit burned before it was switched). However, such a calculation does not accommodate dispatch considerations. With the new, more expensive, lower-sulfur fuel, the affected unit may generate less than it would, if it had been burning its original fuel. Its generation may be reduced by off-system power purchases or cleaner resources.

The examples presented in this chapter were based on a utility with fuel-switching options. Those utilities that choose to scrub one or more of their units are likely to have rather high costs of overcontrol in the near term. As discussed in Chapter 4, standard ratemaking practices cause capital-intensive projects to have higher costs in the early years than in later years. This could cause scrubbers to have rather high annual dollars-per-ton costs in the near term that would decline over time. This is likely to be fundamentally mismatched with the long-term trend of allowance prices. A project that makes economic sense over the long term may lead to early losses that would be offset by later gains. This may discourage low-compliance-cost utilities from overcontrolling their emissions with cost-effective (but capital-intensive) options. To remedy this, a balancing account could be established in which a portion of the early costs of the scrubber could be deferred.

Despite some of these complications, the market-based approach has the potential to significantly benefit the ratepayers and stockholders of many utilities. Given a certain amount of regulatory oversight to ensure that utilities are reporting reasonable compliance assumptions, this regulatory treatment could motivate utilities to pursue least-cost compliance strategies, thereby keeping rates low, while sharing some of the benefits with utilities' stockholders.

Summary

This chapter has presented an incentive ratemaking approach that could encourage utilities to pursue cost-effective opportunities in the allowance market. By providing a mechanism for splitting the benefits from allowance transactions between ratepayers and stockholders, this regulatory treatment could align the interests of both groups and result in lower customer rates and higher corporate earnings than might be the case under conventional ratemaking practices.

The approach is based on a commission's beginning-of-year selection of a dollars-per-ton benchmark value. That value will provide the utility with a ceiling for determining its compliance activities. The utility will be allowed to recover the costs associated with all compliance options that have dollars-per-ton costs that are less than that limit. Any options with costs over the limit will not be given full cost recovery;[13] the utility will only be allowed to recover the costs up to the benchmark value, plus a predetermined percentage of the difference between the costs and the benchmark value (that is, a split-loss provision). For options that result in the overcontrol of a utility's emissions, the utility will be awarded a predetermined percentage of the difference between the benchmark price and the dollars-per-ton cost of the overcontrol option(s).

Utility commissions will have to be careful in reviewing the incremental or differential costs that utilities attribute to their compliance activities since these costs will serve as the basis against which compliance-related gains and savings will be calculated. This additional scrutiny may require more resources from a commission than would be used under traditional ratemaking arrangements; however, such an investment on the part of the regulators may be worthwhile in order to promote the adoption of least-cost compliance plans and allowance trading strategies.

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[13] A commission may want to make this limit more flexible by defining the threshold as the maximum of the benchmark price or the actual allowance market price.

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CHAPTER 7

COMPLIANCE UNCOUPLING APPROACH

Another approach to incentive regulation, which can be called a "compliance uncoupling" approach, employs cost-allocation/risk-sharing features that could encourage potential sellers of allowances to pursue least-cost strategies. This approach would only apply to utilities that have low compliance costs, and are therefore capable of generating excess allowances for sale or later use. However, the approach would not be appropriate for utilities that have high compliance costs and are expected to be buyers in the allowance market.

Basically, the uncoupling approach entails an up-front determination of *overcontrol* compliance activities that would be set aside as quasi-unregulated ventures. These overcontrol activities should represent those compliance options that would:

1. reduce the utility's total emissions below its mandated emissions reduction target (and thereby generate surplus allowances), and
2. have higher projected dollars-per-ton costs than those activities being pursued to meet the utility's mandated reduction obligations.

Graphically these can be described on the utility's stair-step compliance graph (Figure 6-1) as overcontrol activities that are to the right of the utility's mandated emissions reduction requirement. For example, assume that the utility can meet its compliance obligations with fuel-switching activities at several of its affected units. However, the utility has the option of scrubbing one of its units and generating surplus allowances at a cost that it believes will be substantially less than allowance prices over the life of the scrubber. Under the uncoupling approach, the utility's fuel-switching costs would be recovered in a standard manner from ratepayers each year. However, if the utility decided to pursue its scrubbing alternative, the costs of this project would be "uncoupled" and set aside in an unregulated account as a stockholder investment. Likewise, the allowances that the project generated in each year would be uncoupled and set aside in a separate, unregulated allowance inventory. The discussions in this chapter that pertain to allowance inventories are based on the excess allowance accounting perspective (described in Chapter 4).

The difference between this venture and other "below the line," unregulated utility ventures is that a partnership could be formed, *at the commission's discretion*, between the utility's stockholders and ratepayers. If such a partnership were established, the ratepayers would own a percentage of the venture, contributing their percentage of the project's costs and taking the same percentage of any proceeds from allowance sales.

For the purposes of describing the uncoupling approach, it will be assumed that the unregulated activity involves one discrete project. However, the approach could be applied to several projects or even to a portion of a project.

Specifically, the uncoupling approach would involve the following steps:

1. **Filing of Initial Application:** The utility would file with the commission a plan for pursuing an unregulated project. This filing would be similar to a standard compliance filing in that it would include the utility's forecast of allowance prices and project costs; and it would present the utility's justification for the project and describe the potential risks. Indeed, this filing would probably include the utility's entire compliance plan so that the commission could review the project in the context of the other compliance activities that the utility intended to undertake.[1] This would allow the commission to verify that this project was the utility's highest-cost compliance option (among those being implemented) and not one of its cheaper ones. This is important since

[1] The utility would be encouraged to file a compliance plan for the regulated side of its business that resulted in minimal generation of allowances from the regulated activities. The generation of allowances should occur predominantly from the unregulated compliance option(s). Likewise, the regulated compliance plan should not be projected to involve substantial allowance purchases. The uncoupling approach should only be used with utilities that are expected to be allowance sellers.

a utility's cheapest options should be reserved for meeting the company's internal (that is, customers') needs.

2. **Establishment of Financial Partnership:** If the commission felt that the project was attractive, it could establish a financial partnership between the utility's stockholders and ratepayers by agreeing to "fund" some portion of the project. A binding percentage would be established that would dictate both the portion of the project's costs that the ratepayers would contribute and the percentage of the proceeds that the ratepayers would receive from any allowance sales. The determination of what share of the unregulated project the ratepayers should own would be up to the commission. Over the life of the project, the costs would be subject to audit by the commission, but they would not be subject to a prudence review.

3. **Cost Recovery of Capital and Operating Expenses:** The ratepayers' percentage of the project's capital costs would be ratebased just like any other regulated utility project. Similarly, the ratepayers' percentage of the project's yearly operating costs would be expensed in rates just like other regulated activities.

4. **Separation of Allowance Inventories:** Two separate allowance inventory accounts would be established, one for the utility's regulated compliance activities and one for the unregulated project. The second one (the "uncoupled" account) would be used to track the allowances that were generated by the unregulated project.

5. **Annual Review:** At the end of each year, the utility would file a report on the operation of the unregulated compliance project, identifying the costs and emissions reductions attributable to the project. The commission would review and approve these results. The emissions reductions would dictate the number of allowances that would be placed in the uncoupled allowance inventory account.

6. **Accounting for Allowance Transactions:** Whenever the utility sold allowances, the allowances would be supplied from *both* the uncoupled inventory account and the regulated inventory account, if any allowances existed there. The number of allowances supplied from each inventory would be proportional to the balance in each of the accounts at the time of the sale. As footnoted in step 1, the utility should be encouraged to implement a compliance plan that would result in minimal allowance accumulation in the regulated account. Therefore, under expected circumstances, allowance sales should be almost entirely supplied out of the uncoupled inventory account.

   The proceeds from all sales from the uncoupled account would be split between the stockholders and ratepayers based on their funding percentages. The stockholders' portion would be added to earnings as below-the-line income. The ratepayers' portion would be refunded through rates.

   In the event that the utility's regulated compliance activities did not reduce emissions as much as expected and the company needed to acquire allowances in order to meet its obligations on the regulated side, the utility would have two options: it could purchase the necessary allowances on the open market or withdraw allowances from the uncoupled inventory at the market price. If no market price were available, this withdrawal could be made at a benchmark price or indexed value that had been agreed to beforehand. Since the ratepayers already own their percentage of the withdrawal, only the stockholders' portion would be charged through the utility's rates.[2]

Table 7-1 presents the uncoupling approach in the context of the cost recovery framework developed in Chapter 4. As was the case with the market-based approach, an historical test-year basis for describing the rate impacts of the uncoupling approach is

[2] Again, the stockholders' proceeds would be below-the-line income.

TABLE 7-1

COST RECOVERY FRAMEWORK--UNCOUPLING APPROACH

Compliance Costs	Capital Expenditures: Those prudent capital expenditures that are part of the utility's regulated compliance activities (those that meet the utility's mandated emissions reduction target) will be placed in rate base; in addition, the ratepayers' portion of an unregulated project's capital expenditures will be placed in rate base; the undepreciated balance of these ratebased expenditures will be allowed to earn a fair rate of return. Expenses: Those prudent operating expenses that are associated with the utility's regulated compliance activities as well as those that are the ratepayers' portion of an unregulated project will be recovered in rates in the year following the one in which they are incurred.
Allocated Allowances	For ratemaking purposes, a utility's allocated allowances will not be valued.
Allowance Inventory	Inventory Valuation: Not necessary. Return on Inventory: Not applicable.
Purchased Allowances	If the utility makes an allowance purchase, it must indicate for which inventory account, regulated or uncoupled, it is making the purchase. Allowance purchases for the utility's regulated side should be rare. They should only occur when current year allowance deficiencies require them. When this happens, the cost of the allowances will be borne by the ratepayers. For purchases for the uncoupled account, ratepayers and stockholders will split the costs based on the partnership percentages.
Sold Allowances	The proceeds from sales of allowances from the uncoupled account will be split between the utility's ratepayers and stockholders in the year of the transaction based on the partnership percentages. Proceeds associated with allowances from the regulated account will go entirely to the ratepayers.

assumed. However, the uncoupling approach will also work under future test-year arrangements.

Unlike other ratemaking treatments that require the calculation of the *gains* from allowance sales, this approach only needs the determination of the total *proceeds* of the sale (that is, the price of the allowances times the number sold). This eliminates, for ratemaking purposes, the complexities of calculating a dollars-per-ton cost basis for allowances that are generated.[3] Such a basis is only needed when determining gains. All of the complications that go along with dollars-per-ton cost calculations can be avoided under the uncoupling approach. Therefore, the commission will not need to make any judgments concerning the valuation of either the utility's allocated allowances or its allowance inventories. Just as the uncoupled allowance inventory will not be valued for ratemaking purposes, neither should it earn a return. Obviously, without the first process, the second would be impossible. However, this aside, there is a fundamental rationale for not allowing the utility to earn a return on the uncoupled allowance inventory--namely, both the stockholders and the ratepayers will earn their respective returns on their investment upon the sale of allowances. The stockholders should not be guaranteed a return, as is the case for standard ratebased investments. Since the utility's stockholders will only realize gains when the excess allowances are sold, the utility will have an incentive to monitor the market closely and sell the allowances at the earliest appropriate time. Long-term banking of allowances will only be justified if the utility expects allowance prices to increase at a rate that is greater than its stockholders' desired return.

In order to ensure appropriate management of the project, both parties should share a substantial interest in the venture (for example, a 50 percent/50 percent split). If the stockholder's percentage is too small, there may not be enough profit in the venture to encourage the utility to be diligent in managing the project and pursuing opportunities in the allowance market. If the ratepayers' percentage is too small, it would increase the incentive for the utility to cross-subsidize its unregulated project with resources from the utility's regulated side. These issues will be addressed in more detail in the discussion of the advantages and disadvantages of the approach.

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[3] The calculation of dollars-per-ton cost basis may need to be done for financial accounting and tax accounting purposes. However, the uncoupling approach allows a commission to side-step this complicated issue and leave it to the Financial Accounting Standards Board and the IRS.

A Selling Utility--An Example

To illustrate the uncoupling approach, we will assume the same hypothetical utility that was used to examine the selling scenario of the market-based approach in Chapter 6. The projected and actual circumstances that the utility faces in 1995 are displayed in Table 7-2. Assume that the utility expects allowances to sell for $300 per allowance at the end of 1995.

Based on projections, the utility expects to be able to meet its mandated emissions reduction target merely by fuel switching at BIGCOAL 1. Assume that the utility believes that allowances will sell for $300 per allowance at the end of 1995. Given its projected costs for fuel switching at BIGCOAL 2, the utility predicts that it could overcontrol its emissions and generate 30,000 allowances for sale at a profit. The fuel-switching option at BIGCOAL 3 appears to be too expensive to justify.

The utility therefore files a compliance plan with its regulatory commission, applying for an uncoupled status for the BIGCOAL 2 fuel-switching project. The commission grants that status on the condition that the utility accepts a 50 percent/50 percent partnership on the project with its ratepayers. Assuming that this partnership percentage is acceptable, the utility would embark on its plan to fuel switch at BIGCOAL 1 and 2.

At the end of the year, the utility files a report with the commission that documents the achievements of the regulated and uncoupled compliance activities. As can be seen in Table 7-2, the utility's emissions were 95,000 tons of sulfur dioxide (SO_2), leaving it with 25,000 surplus allowances. Only 20,000 of these 25,000 allowances were attributable to the BIGCOAL 2 fuel-switching project. The BIGCOAL 1 fuel-switching activity accounted for the other 5,000 allowances. This compliance option achieved

TABLE 7-2

SELLING UTILITY ASSUMPTIONS--UNCOUPLING APPROACH

Circumstances	**1995-Projected**	**1995-Actual**
Uncontrolled Utility Emissions: (tons of SO_2/year)	170,000	175,000
Allocated Allowances: (allowances/year)	120,000	120,000
Mandated Emissions Reduction Target: (tons of SO_2/year)	50,000	55,000
Fuel Switching at BIGCOAL 1		
Reduced Emissions (tons of SO_2/year):	50,000	60,000
Total Cost ($M):	$12·5	$15·6
Annual Incremental $/Ton Cost:	$250	$260
Fuel Switching at BIGCOAL 2		
Reduced Emissions (tons of SO_2/year):	30,000	20,000
Total Cost ($M):	$8·4	$5·4
Annual Incremental $/Ton Cost:	$280	$270
Fuel Switching at BIGCOAL 3		
Reduced Emissions (tons of SO_2/year):	60,000	0
Total Cost ($M):	$19·2	$0
Annual Incremental $/Ton Cost:	$320[1]	--
Final Utility Emissions: (tons of SO_2/year)	90,000	95,000
Surplus Allowances:	30,000	25,000
Partnership Percentage: (Ratepayer/Stockholder)	50%/50%	

[1] Since this compliance option's projected cost is greater than the expected price of allowances, the utility will not implement the option.

60,000 tons of SO_2 emissions reduction, thereby exceeding the utility's mandated emissions reduction target, which was determined at the end of the year to be 55,000 tons. Therefore, the regulated and uncoupled allowance inventories would have the balances shown in Table 7-3 at the end of the year.

TABLE 7-3 REGULATED AND UNCOUPLED ALLOWANCE INVENTORY BALANCES	
Regulated Allowance Inventory	Uncoupled Allowance Inventory
5,000	20,000

Assume that the utility sold all 25,000 allowances at the end of the year for $300 per allowance. The proceeds from the regulated inventory would be $1.5 million[4] and would go directly to the ratepayers. The proceeds from the uncoupled inventory would be $6 million[5] and would be split 50 percent/50 percent between the stockholders and ratepayers.

The net benefits of the uncoupling approach can be assessed by comparing the costs and revenues of this scenario with those of the traditional ratemaking approach. Under the uncoupling treatment, the ratepayers will be responsible for the full $15.6 million for fuel switching at BIGCOAL 1. These costs, however, will be offset by the allowance sales revenues that this activity generated ($1.5 million). Thus, the net cost of the BIGCOAL 1 fuel switching is $14.1 million.[6] The fuel-switching costs at BIGCOAL 2 were $5.4 million and would be split between the stockholders and

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[4] $1.5 million = 5,000 allowances x $300 per allowance.

[5] $6 million = 20,000 allowances x $300 per allowance.

[6] $14.1 million = $15.6 million - $1.5 million.

ratepayers, with each group paying $2.7 million. Each group would also receive their percentage of the proceeds from the sale of the 20,000 allowances that the investment generated. Thus, each group's cost would be offset by $3 million in revenues.[7] This would have the effects on revenue requirements and earnings presented in Table 7-4.

Under a traditional approach, the utility would have had no incentive to pursue the fuel-switching activity at BIGCOAL 2. Likewise, it may have been inclined to reduce its use of low-sulfur coal at BIGCOAL 1 so that it just met its mandated reduction obligations. In this case, it would have foregone the potential gains from allowance transactions, paying $14.3 million[8] in fuel-switching costs. In comparison to this situation, the uncoupling approach would provide the utility's ratepayers and stockholders with the net benefits shown in Table 7-5.

TABLE 7-4

UNCOUPLING EXAMPLE'S EFFECTS ON
REVENUE REQUIREMENTS AND EARNINGS

Revenue Requirements:	
$15.6 million	BIGCOAL 1's costs
-$1.5 million	Sales Revenues--5,000 allowances
$2.7 million	50% of BIGCOAL 2's costs
-$3.0 million	50% of Sales Revenues--20,000 allowances

$13.8 million	Net Compliance Costs
Earnings:	
$2.7 million	50% of BIGCOAL 2's costs
-$3.0 million	50% of Sales Revenues--20,000 allowances

-$0.3 million	Net Stockholder Costs

[7] $3 million = $6 million x 50%.

[8] $14.3 million = $15.6 million x (55,000/60,000).

TABLE 7-5 NET RATEPAYER AND STOCKHOLDER BENEFIT IN UNCOUPLING EXAMPLE	
Revenue Requirements	$0.5 million less[1]
Earnings	$0.3 million more[2]

[1] $0.5 million = $14.3 million - $13.8 million.
[2] As calculated above as the negative net "costs" (that is, profits) of participation in the deregulated project.

Thus, both the ratepayers and the stockholders would be better off in this situation.

Advantages and Disadvantages

The benefit of the uncoupling approach is that it aligns the interests of the utility's ratepayers and stockholders by making them partners in the unregulated project. In looking out for the interests of stockholders, utility management will simultaneously benefit ratepayers. The partnership between the two groups will eliminate the adversarial nature that is prevalent in traditional ratemaking arrangements, whereby one group benefits at the other's expense. Both groups will benefit from the utility's careful and realistic planning at the outset, conscientious attention to minimizing the project's costs, and vigilant pursuit of the highest allowance prices.

The uncoupling approach also provides a better alignment of risk and reward than other regulatory treatments. The potential gains or losses from an unregulated project will be distributed based on each party's level of investment. Therefore, the rewards will accrue to those whose investment is at risk. In addition, as mentioned above, the uncoupling approach does not require the explicit calculation of *gains* from allowance sales. The difficulties of determining and using dollars-per-ton compliance costs for ratemaking can be avoided.

As far as drawbacks, the uncoupling approach can only be used as an incentive mechanism for utilities likely to be *sellers* in the allowance market. It is not applicable to allowance-purchasing utilities. Also, as is the case with any unregulated utility venture, the regulatory commission will have to be careful to monitor and verify the separation of regulated and unregulated activities. Potentially, a utility could cross-subsidize its unregulated ventures with resources from its regulated side. Thus, the ratepayers would pay for more of the unregulated activities than was dictated in the uncoupling agreement. The unregulated venture would appear to be cheaper and more profitable than it really was, and the utility's stockholders would receive a portion of these inflated profits. However, the larger the ratepayers' percentage of the unregulated project, the fewer benefits there are for the utility's stockholders from any cross-subsidization. Also, such cross-subsidization will be minimized if the utility is required to file a compliance strategy update at the beginning of each year that clearly defines the regulated and unregulated activities.

Another potential problem involves the determination of overcontrol compliance activities. As fuel prices and other compliance-related costs fluctuate over time, an activity that appeared to be the overcontrol option in 1995 may by 1998 become less expensive relative to other utility compliance activities. One possible arrangement would be to grant unregulated status for the life of a project. The determination of whether or not a compliance option was the utility's highest-cost activity would be made from the utility's initial filing. Thus, a capital-intensive project, such as a scrubber, or a future commitment, such as from a long-term fuel contract, would be deemed an overcontrol activity if its projected costs exceeded those of the utility's other compliance options over the project's lifetime.

Last, one could argue that the uncoupling approach could result in the intergenerational transfer of wealth among ratepayers. This could happen if an unregulated project had high up-front costs and low long-term costs. Over the life of the venture, the project may be profitable. However, the majority of the profits might be in the future. Selling allowances in the near term might result in losses. Alternatively, a utility may choose to bank the uncoupled allowances for future sale. In this case, near-term ratepayers would pay for the generation of allowances, yet the benefits of the sales of these allowances would accrue to future ratepayers. It is unlikely, though, that utilities will commit substantial amounts of their stockholders' funds to long-term price speculation. One of the major benefits of the uncoupling approach is that it discourages excessive banking. For example, utilities are unlikely to invest in an unregulated venture in 1995 in order to generate allowances that they do not intend to sell for ten years unless they are confident that allowance prices will rise enough to financially justify such a long-term investment. Therefore, it is unlikely that intergenerational wealth transfer between ratepayers will be a problem.

Summary

This chapter presents a new regulatory incentive treatment that could be useful in encouraging potential allowance sellers to pursue profitable opportunities in the allowance market. The compliance uncoupling approach allows for the establishment of unregulated compliance activities whose sole purpose would be the generation of surplus allowances. These allowances would be generated by the reduction of a utility's annual emissions below its number of allocated allowances. At the end of each year, an assessment would be made to determine the number of allowances that had been freed up by the unregulated project. These allowances would be placed in a separate, uncoupled allowance inventory. All costs of the project would be borne by the stockholders unless the regulatory commission determined that it would be beneficial for the utility's ratepayers to participate in the unregulated project. In that case, the commission would establish a percentage of the project that would be funded by ratepayers. That same percentage would be the portion of the revenues that the ratepayers would receive from any allowance sales that the utility made from the uncoupled allowance inventory. The uncoupling approach dismisses the need to value allowances for ratemaking purposes, thereby avoiding some of the complications associated with dollars-per-ton compliance calculations.

This regulatory treatment would establish a partnership between a utility's ratepayers and stockholders, thereby aligning their interests in pursuing profitable opportunities in the allowance market. Like any unregulated venture, however, the potential exists for cross-subsidization, where a utility's regulated resources are used to assist unregulated ventures. Therefore, commissions will have to closely monitor the utility's regulated and unregulated compliance activities to make sure that this does not happen. If such precautions are taken, the uncoupling approach could successfully promote profitable allowance inventory management for the benefits of ratepayers and stockholders.

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CHAPTER 8

CONCLUSION

The Clean Air Act's allowance trading program presents new challenges for public utility commissions. Substantial savings may be realized if utilities are encouraged to pursue cost-effective compliance strategies and allowance transactions in the emerging national market. The application of traditional ratemaking practices may not provide this encouragement. In fact, it was seen in Chapter 5 that such practices may introduce undesirable biases and cause customer rates to be higher than necessary.

An approach taken so far by several commissions is to use an automatic passthrough of compliance costs and allowance purchases. For fuel costs, the most common use of these types of procedures, the incentive to minimize costs are weak at best.[1] The use of these procedures for allowances and compliance costs may be particularly inappropriate, especially when combined with a weighted-average inventory method, historical cost basis, and all the utility's allowances are combined together in one inventory account. The same lack of incentive to minimize compliance costs, described above, exists whether the costs are handled in a rate case or through an automatic procedure.

Commissions should also recognize that a utility should not be rewarded for simply participating in the market. Trading allowances in-and-of-itself is *not* the goal; rather, the goal is to encourage utilities to develop and implement cost effective compliance strategies. Commissions can adopt procedures that link the utility's compliance activities with the market price. To date, no commission has done this, although at least two commissions have indicated that they will consider incentive proposals from their utilities.

[1] See, for example, Robert E. Burns, Mark Eifert, and Peter A. Nagler, *Current FAC and PGA Practices: Implications for Ratemaking in Competitive Markets* (Columbus, OH: The National Regulatory Research Institute, 1991).

The incentive methods discussed in this report were designed to encourage utilities to purchase allowances or invest in compliance options when it is cost effective. This induces the utility to behave as a competitive firm would, that is, minimize its costs. Unlike command-and-control environmental programs, the trading program creates a market to remedy the problem of a market failure. This results in there being more responsibility on the part of the economic regulators to see that utilities are encouraged to take the opportunity to use the market.

Ordinarily, it is difficult to use and evaluate an incentive program, such as plant performance incentives (for example, heat-rate targets). A major reason for this is because the commission must determine the performance level or benchmark. However, since there is a market price of allowances to compare with the utility's performance, the commission's task becomes considerably less difficult. Under the market-based ratemaking approach the market price of allowances becomes, in effect, the benchmark or the standard of prudence. The utility is then encouraged to consider allowances as a factor of production that it can produce itself, but only when it is cost effective to do so.

It is important to recognize that the SO_2 allowance trading system itself is a national incentive mechanism. Developing a regulatory incentive system that dovetails with the national market is likely to encourage the development of that market. Moreover, it could be argued that some type of incentive system is required for the development of an *efficient* market. This is because current regulatory practices will not provide sufficient incentive to use the market. Although a market-based ratemaking mechanism will not guarantee that the expected saving will materialize, such a mechanism may make it much more likely.

Thus far, utilities have chosen self-sufficient compliance strategies, with one notable exception. That is, taking compliance actions and generating allowances for their own system's needs. Ratepayers will likely be paying for this overcontrol, whether it is cost-effective or not. Since many of the phase I compliance plans have been approved (or preapproved) by commissions, utilities are unlikely to return to the commission to revise these approved plans.[2] However, since utilities are just beginning to discuss with their commissions their phase II

[2] As has been pointed out in previous NRRI reports, preapproval, because of this lack of flexibility and other reasons, is in direct conflict with a market-based environmental system.

strategies, more compatible ratemaking can be applied for these actions.

It is important to also consider that all states, including states that have very low compliance requirements or do not need to take any action to be in compliance (such as western states), can benefit. Utilities in states with relatively low compliance requirements are low-cost sources of overcontrol and allowances. As was demonstrated, traditional regulation is unlikely to encourage these utilities to pursue these opportunities that could benefit ratepayers. Also, as has already been seen, most utilities with considerable compliance requirements are foregoing the opportunity to purchase allowances that are considerably less expensive than the cost to these utilities of generating allowances themselves. Ratepayers in these states will benefit from lower compliance costs that should result from a more compatible regulatory approach.

Previous NRRI reports and others[3] have explained the theoretical reasons why a utility will not minimize its compliance costs under traditional regulation; the numerical example in Chapter 5 explains, by example, why this would occur; and phase I utility actions thus far indicate that this is in fact occurring. Taken together, this is compelling evidence that traditional economic regulation simply does not mesh well with the market-based environmental program.

A recent EPRI analysis[4] of the cost savings from trading gives an idea of the magnitude of the potential benefit to ratepayers. EPRI estimated the cost of a phase II level of reduction with:
(1) command-and-control environmental regulation,
(2) intrautility trading only, (3) a constrained level of interutility trading, and
(4) "perfect trading," that is, utilities always making cost-effective decisions on compliance choices and buying and selling allowances. The cost difference (or savings) between command-

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3 Kenneth Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, 1992), Chapters 7 and 9; Kenneth Rose and Robert E. Burns, eds., *Regulatory Policy Issues and the Clean Air Act: Issue and Papers from the State Implementation Workshops* (Columbus, OH: The National Regulatory Research Institute, 1993); and Douglas R. Bohi and Dallas Burtraw, "Utility Investment Behavior and the Emission Trading Market," *Resources and Energy*, 14 (1992): 129-53.

4 Electric Power Research Institute, *Integrated Analysis of Fuel, Technology and Emission Allowance Markets: Electric Utility Responses to the Clean Air Act Amendments of 1990,* EPRI TR 102510 (Palo Alto, CA: Electric Power Research Institute, November 1993).

and-control and perfect trading were estimated to be $2.9 billion. This is similar to earlier estimates made about the time the CAAA was passed.[5]

If current regulatory practice continues along the same pattern of the traditional approach, then there may be very little interutility trading in phase II as has been seen so far with phase I compliance (as noted in Chapter 2). If this is the case, then the unrealized cost savings, using the EPRI estimates, would be between $600 million to $1.2 billion per year[6] (1992 dollars). It is unlikely, of course, that "perfect" trading would ever occur, even in a competitive industry. However, a conservative estimate of $0.5 billion to $1 billion per year in cost savings is, even for the electric industry, a considerable sum.[7] The actual savings may be greater since these estimates do not take

[5] Paul R. Portney estimated the savings as being up to $3 billion per year. See Paul R. Portney, "Policy Watch: Economics and the Clean Air Act," *Journal of Economic Perspectives* 4, no. 4 (1990): 173-81.

[6] The $600 million is the difference between the intrautility-trading-only scenario and the "constrained" interutility trading. The $1.2 billion is the difference between the intrautility trading only and "perfect" interutility trading.

[7] For comparison, consider that utility revenue from "other" sources, primarily wholesale power sales revenues, in 1991 were about $8.5 billion. The higher estimate of the cost savings is 14 percent of these other revenue sources. The "other revenue" figure is taken from Edison Electric Institute, *Statistical Yearbook 1991*, No. 59 (Washington, D.C.: Edison Electric Institute, October 1992), Table 57, 64.

into account the increase in efficiency by the utility in developing and implementing a compliance strategy that would be likely under an incentive approach.[8]

The two incentive ratemaking treatments, the market-based approach and the compliance uncoupling approach, both provide utilities with incentives to develop cost-effective compliance strategies and use the allowance market when appropriate. Both allow for the utility and ratepayers to share in the benefits (and risks) associated with allowance market transactions. Table 8-1 summarizes the benefits and drawbacks of the three regulatory approaches discussed in the report.

There is little doubt that current regulatory mechanisms can be modified to cope with the CAAA. When choosing their regulatory procedures, commissions should consider the effect of their actions on the development of the allowance market and regard it as an important cost-saving factor. A change from traditional to more incentive- or market-based regulation is intended to improve the chance of success of the allowance market and minimize the compliance costs ratepayers will have to incur.

An additional benefit to commissions developing an effective means of dealing with the national SO_2 allowance program, is that the same regulatory approaches could be applied to other national and regional market-based environmental control programs. California (the South Coast Air Quality Management District) has used an emissions offset program for volatile organic compounds for over ten years and for other pollutants more recently[9] and is currently considering a modified trading system.[10] Also, eight

[8] That is, increasing X-efficiency of the utility. For example, encouraging the utility to pursue and implement compliance options more efficiently in terms of cost control and management.

[9] Robert W. Hahn and Gordon L. Hester, "Where Did All the Markets Go? An Analysis of EPA's Emissions Trading Program," *Yale Journal on Regulation* 6, no. 1 (Winter 1989).

[10] South Coast Air Quality Management District, "Regional Clean Air Incentives Market: Summary Recommendations" (Diamond Bar, CA: South Coast Air Quality Management District, Spring 1992).

TABLE 8-1

ADVANTAGES AND DISADVANTAGES TO THE THREE RATEMAKING APPROACHES

Approach	Advantages	Disadvantages
Traditional	Uses conventional regulatory methods with which commissions are familiar. May require less administrative resources on the part of the regulators than other ratemaking approaches.	Will not encourage utilities to manage allowance inventories in a cost-effective manner. Could cause utilities to buy and sell allowances unnecessarily, merely to swap their zero-cost allowances for market-price allowances. May lead to higher customer rates and lower corporate earnings than other ratemaking approaches.
Market-Based	Provides a clear predetermined benchmark price to guide a utility's compliance decisions. Provides for a sharing of the gains and losses associated with allowance transactions. May lead to lower customer rates and higher corporate earnings than the traditional approach. Can encourage utilities to develop and implement innovative approaches to compliance.	Requires calculating incremental compliance cost to determine gain or loss.
Compliance Uncoupling	Aligns the interests of ratepayers and stockholders. Clearly grants rewards of overcontrol to those who bear the risks. May lead to lower customer rates and higher corporate earnings than the traditional approach. Can encourage utilities to develop and implement innovative approaches to compliance.	Can only be used for utilities that are expected to be allowance sellers. Potential for cross-subsidization.

states in the northeast have proposed a multistate trading system[11] and a trading system is being considered for at least two urban areas (Chicago and Houston-Galveston). National and even global carbon dioxide trading have been discussed. Eventually, much or most of a utility's environmental compliance could be associated with market-based environmental programs. These programs would also function more efficiently within compatible economic regulatory procedures. Further study is required, however, on how these varied programs can be coordinated by a commission in an incentive approach.

With the passage of the Energy Policy Act of 1992, the utility industry will continue to become increasingly competitive and market-oriented. The issues addressed in this legislation are likely to have a major impact on the structure of the electric service industry. In addition to the cost savings that can be achieved with market-based environmental approaches, the knowledge and experience gained from such arrangements could prove valuable in preparing utilities and regulators for a more market-based regulatory environment in the future.

[11] Northeast States for Coordinated Air Use Management (NESCAUM), "Development of a Market-Based Emissions Cap System for NO_x in the NESCAUM Region: Project Summary for Section 105 State Air Grant Funds for Market-Based Initiatives" (Boston, MA: NESCAUM, 1992).

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APPENDIX A

COMPLIANCE OPTIONS THAT DIRECTLY REDUCE EMISSIONS

Flue Gas Desulfurization (FGD)

Commonly known as "scrubbing," FGD removes sulfur dioxide (SO_2) from combustion gases (through absorption in a chemical absorbent such as wet limestone or lime) emitted by a coal-fired plants. A large array of technologies are available that use the FGD process. The different FGD technologies vary as to removal efficiency (percentage of SO_2 removed per unit of chemical absorbent consumed), generation of wastes and reusable byproducts, technological feasibility, performance history, and cost.[1] Scrubbing is currently the most widely used SO_2 control option. Also, conventional scrubbers can be retrofitted to reduce nitrous oxide (NO_x) emissions and more advanced scrubber designs generally include improved NO_x control.

Repowering and Clean Coal Technologies (CCTs)

CCTs may generally be defined as processes or techniques that reduce the sulfur content of coal prior to, during, or after the combustion process in a coal-fired plant. CCTs may be divided into four groups. They are (1) precombustion cleaning,
(2) clean combustion, (3) coal conversion, and (4) postcombustion cleaning.

Precombustion cleaning includes physical cleaning of the coal through such processes as froth floatation, gravity separation and electrostatic separation, and

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[1] For a comprehensive assessment of FGD technologies, see Electric Power Research Institute, *Economic Evaluation of Flue Gas Desulfurizaton Systems*, RP 1610-6 (Palo Alto, CA: Electric Power Research Institute, February 1991).

biological-chemical cleaning through leaching with chemical reagents and digesting by bacteria and enzymes.[2]

Clean combustion techniques consist of controlling the combustion parameters (for example, fuel, oxygen, and temperature) to minimize the formation of pollutants and/or injecting pollution-absorbing substances into the combustion chamber to capture the pollutants as they are formed. The more well-known clean combustion technologies include atmospheric fluidized bed combustion and pressurized fluidized bed combustion.[3] Clean combustion technologies can be used to build new plants, as well as to repower existing plants. Repowering an existing plant with a CCT reduces pollutant emissions in two ways. The increased thermal efficiency (lower heat rate) achieves the same energy production with a smaller quantity of fuel and therefore, with a lower emission of pollutants. Also, all clean combustion CCTs are equipped with devices that directly reduce pollutant emissions even further.

Coal conversion techniques include gasification and liquefaction of coal. The most well-known technology that utilizes the coal conversion process is integrated gasification combined cycle (IGCC).[4] The IGCC process features two steam generation units: one burns coal and the other burns gasified coal.

Postcombustion cleaning is the process used by conventional FGDs. Therefore, conventional FGDs may also be considered CCTs. However, because of the fact that conventional FGDs have a longer performance history relative to other CCTs, conventional FGDs are generally treated as a separate set of technologies than CCTs. CCTs that use postcombustion cleaning include advanced design scrubbers with potentially higher removal efficiencies than conventional designs. Advanced scrubbers also include techniques and devices to generate dry, saleable byproducts and achieve improved NO_x reduction.

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[2] U.S. Department of Energy, *Clean Coal Technology Demonstration Program: Program Update* (Washington, D.C.: U.S. Department of Energy, February 1993), 1-10.

[3] Ibid., 1-10 through 1-11.

[4] Ibid., 1-12 and 1-13.

Emissions Dispatch

An effective way to reduce pollutant emissions is to reorder the load dispatch of power plants. For example, if plants are dispatched in order of increasing emission levels, the plant with least emissions is dispatched first and system pollutants are significantly reduced. Traditionally, plants are dispatched in increasing order of their variable costs. Rearranging the dispatch order according to emission levels, known as least emissions dispatching, can achieve significant reduction of pollution control costs.

Although least emissions dispatching may reduce environmental costs, it may add to fuel and other operating costs of the system. The reduction in environmental costs may not completely offset the increase in operating costs. Therefore, use of least emissions dispatching may not be the least-cost approach of system operation. A better approach may be full cost dispatch, which uses the aggregate of operating costs and environmental costs to select the dispatching order.[5]

Emissions dispatching[6] is an attractive option, particularly for existing plants, because it avoids the additional expense of building pollution control equipment. It also can be used effectively for new plants. In a sense, emissions dispatching is not in competition with other environmental compliance options and can be used on any generation system, however configured, to achieve additional reductions in environmental compliance costs. The reason is that all the other options involve resource acquisition, while emissions dispatching is a pure system operation choice. The two kinds of choices are, therefore, essentially independent (that is, if one is chosen, the others are not precluded).

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[5] Stephen Bernow, Bruce Biewald, and Donald Marron, "Full Cost Dispatch: Incorporating Environmental Externalities in Electric System Operation," *The Electricity Journal* (March 1991): 20-33. See also, Roland Kraatz, "SO_2 Trading Impacts on a Utility: Internalizing an Externality," presented at the Workshop on Market-Based Approaches to Environmental Policy, sponsored by the Department of Economics, University of Illinois at Chicago, February 17, 1993.

[6] In this report, emissions dispatching is used to mean any modification in the dispatch order based on an emission-based criteria. Thus, for purposes of this report, least emissions dispatching and full cost dispatching are both different forms of emissions dispatching.

Fuel Switching

There are two basic fuel switching options. In coal switching, high-sulfur coal is either replaced by or blended with low-sulfur coal to reduce SO_2 emissions. In natural gas cofiring, natural gas and coal are used in combination. Since natural gas contains almost no sulfur, this process can significantly reduce SO_2 emissions. Unlike gas cofiring, coal switching can adversely effect material properties of a unit's full blend and reduce combustion efficiency. This problem can be addressed by retrofitting the boiler for better low-sulfur coal combustion or using low-sulfur coal with chemical and physical properties close to the original high-sulfur coal.

Use Cleaner Fossil Fuels and CCTs for New Capacity

The utility may be limited in its choice of pollution control options for existing plants. Due to design and operating limitations, many existing plants may not be amenable to retrofits of pollution control equipment, fuel switching, and repowering. For new capacity needs for meeting future demand growth, there is a wider array of options available to comply with environmental regulations. The possible choices include cleaner fossil fuels (gas and low-sulfur coal) and CCTs. If gas prices do not rise significantly in the future, burning gas alone or concurrently with coal (in a combined-cycle plant) is a promising option. CCTs, which are likely to achieve commercial viability (that is, become economically competitive with existing technologies) in the next five to ten years, may also become an important part of a utility's resource mix.[7]

Use Nonfossil Technologies for New Capacity

A utility can use nonfossil technologies to meet its need for new capacity. The well-

[7] For an overview of current status of development of CCTs, see U.S. Department of Energy, *Clean Coal Technology Demonstration Program: Program Update* (Washington, D.C.: U.S. Department of Energy, 1992).

known renewable technologies, solar, wind, and geothermal[8] (which are relatively pollution free), are currently being used in commercial operation only in certain regions on a limited scale. For most utilities faced with significant compliance requirements, renewables do not represent a commercially viable option at the present time because of their high capital costs. Ongoing federal and industry efforts at developing improved renewable technologies may produce commercially viable technologies in the future.[9]

Nuclear power technology could be an effective option for meeting the compliance requirements of the Clean Air Act Amendments of 1990 (CAAA). Like renewables and unlike fossil-fired plants, it does not generate SO_2, NO_x and other criteria pollutants. Other public safety and environmental concerns, however, may make this technology a relatively unattractive compliance option. Also, the historical experience of regulatory disallowances of large nuclear plants may make utilities particularly averse to include this technology in their resource plans. However, the expedited licensing process for new nuclear plants and the reform of the site characterization rules for Yucca Mountain high-level nuclear waste repository mandated by the Energy Policy Act of 1992 (EPAct) may improve the prospects for nuclear power

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[8] Technically speaking, geothermal is not a renewable resource because it is depletable (unlike solar or wind). However, it is generally treated as a renewable resource.

[9] Jan Hamrin and Nancy Rader, *Investing in the Future: A Regulator's Guide to Renewables* (Washington, D.C.: The National Association of Regulatory Utility Commissioners, February 1993). See also, Oregon Public Utility Commission Staff, "Photovoltaics: Technology Status and Development Potential in Oregon," *NRRI Quarterly Bulletin* 14, no. 3 (September 1993), 311-21.

technology.[10] Also, ongoing federal and industry efforts to develop safer and more efficient nuclear designs may hold some promise for this technology beyond the next decade.[11] Nevertheless, it is difficult to speculate whether and when the nuclear option is likely to gain a place in the nation's mix of new resources and contribute as a relatively pollution-free substitute to fossil-fired generation.

Options that Modify Generation Requirements

These options do not reduce emission rates of pollutants from generating plants operated by the utility. Instead, they reduce emissions by reducing generation requirements. Options that fall under this category are load management, conservation and other demand-side management (DSM) options, and power purchases from other utilities, cogenerators, and independent power producers.

DSM Options

DSM options have been increasingly used by utilities over the last decade as a result of state commission initiatives promoting the integrated resource planning (IRP) approach to utility resource planning.[12] In contrast to the traditional approach to planning, which considered only

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[10] For an overview of provisions of EPAct that affect nuclear power plant licensing and nuclear waste disposal, see Kenneth W. Costello et al., *A Synopsis of the Energy Policy Act of 1992: New Tasks for State Public Utility Commissions* (Columbus, OH: The National Regulatory Research Institute, June 1993), 53-56 and 64-66.

[11] The U.S. Department of Energy, *National Energy Strategy: Powerful Ideas for America* (Washington, D.C.: U.S. Government Printing Press, February 1992), 34.

[12] For an overview of the IRP approach to utility planning, see Martin Schweitzer, Evelin Yourstone, and Eric Hirst, *Key Issues in Electric Utility Integrated Resource Planning: Findings from a Nationwide Study* (Oak Ridge, TN: Oak Ridge National Laboratory, April 1990). For an overview of IRP implementation, see Martin Schweitzer, Eric Hirst, and Lawrence J. Hill, *Demand-Side Management and Integrated Resource Planning: Findings from a Survey of 24 Electric Utilities* (Oak Ridge, TN: Oak Ridge National Laboratory, February 1991).

supply side options as decision variables, the IRP approach requires equal consideration of both supply side and demand-side alternatives. Demand-side options are designed to modify the demand profile of customers and potentially can reduce both the capacity and the energy demanded. This results in fewer power plants being built and less energy being generated from existing plants, leading to a reduced level of pollutants being emitted.

Besides reducing the level of pollutants, DSM options have an additional benefit for utilities when used to meet compliance requirements of the CAAA. Utilities exercising DSM options under a state commission-approved IRP may also be qualified to receive bonus allowances from the conservation and renewable energy allowance reserve.[13] Thus, DSM options can be a significant part of a utility compliance plan.

Power Purchases

Utilities also can reduce their generation requirements by purchasing power from cogenerators and qualifying facilities, and independent power producers. Over the last decade, the implementation of the Public Utility Regulatory Policies Act of 1978 (PURPA) requirements and the growing competition in generation have led utilities to increasingly purchase power from nonutility generators (NUGs). EPAct further promotes power purchases from NUGs through its reform of the Public Utilities Holding Company Act of 1935 and facilitates a further expansion of the electricity wholesale market. The increase in competition in the wholesale power market is likely to drive down prices and make purchased power an attractive option for utilities both as a substitute for self-generation and for meeting compliance requirements.

Purchase or Sale of Allowances

[13] Section 404(f) of the CAAA. Final rules promulgated by EPA, December 1992--40 CFR §§ 72.43 and 72.91, and Part 73, subpart F. For a summary of the CAAA provision see Kenneth Rose et al., *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program* (Columbus, OH: The National Regulatory Research Institute, 1992), 10-13.

The trading of emission allowances is the primary mechanism through which Title IV of the CAAA purports to efficiently allocate resources (provided the allowance program is successful) to achieve mitigation of pollutant emissions from electric generating plants. Whenever a utility's marginal pollution control cost is higher than the prevailing market price of allowances, it is more cost-efficient to purchase allowances than invest in pollution control options. On the other hand, if the allowance price is higher than the marginal pollution control cost, it is profitable for the utility to overcontrol and sell the surplus allowances to another utility. In addition, a utility can also bank allowances to either provide for future compliance requirements or to sell the allowances in the future.

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APPENDIX B

SUMMARY OF STATE COMPLIANCE ACTIVITY

In the summer of 1993, a survey was conducted to monitor state actions on implementing the Clean Air Act Amendments of 1990 (CAAA), including the forty-nine affected state public utility commissions (the forty-eight contiguous states plus the District of Columbia; Alaska and Hawaii are not affected by the CAAA). The results are summarized in the following table. The information presented here is from a survey that was conducted through telephone interviews with state commission staffs, and from conversations with the Edison Electric Institute and Terra Group staffs, and from information drawn from a previous NRRI report.[1]

Several actions and approaches used by state commissions that are summarized in the table are discussed in more detail in Chapter 2 of this report.

[1] Kenneth Rose and Robert E. Burns, *Regulatory Policy Issues and the Clean Air Act: An Interim report on the State Implementation Workshops* (Columbus, OH: The National Regulatory Research Institute, August 1992).

State	Public Utility Commission	Other Regulatory Actions
Alabama	No activity noted.	No activity noted.
Arizona	No activity noted.	Elected Section 406.
Arkansas	Commission guidelines specify IRP planning must include externality costs (e.g. SO_2).	Elected Section 406.
California	Commission informally studying allowance trading allocation of revenues.	Deferred to be Clean State.
Colorado	No activity noted.	Elected Section 406.
Connecticut	Docket 92-04-01 determined that future IRPs should include phase II allowance values in calculating avoided costs.	State law 92-106 required utilities to file a plan on proposed revenue treatment of allowances. State law also mandates a 1.1 pounds of SO_2 per mmBtu cap for oil- and coal-fired units.
Delaware	No activity noted.	No activity noted.
District of Columbia	Commission staff endorsed a cost-recovery surcharge mechanism in Potomac Edison case.	No activity noted.
Florida	Generic docket 930-169-EL on net income neutrality.	Law 92-132 allows preapproval of compliance plan. A 1993 statute allows recovery through environmental cost recovery factor separate from base rates.
Georgia	Docket opened to investigate trading, usage, and ratemaking issues of emission allowances.	H.B. 280 requires IRP to include compliance plan.
Idaho	No activity noted.	No activity noted.

State	Public Utility Commission	Other Regulatory Actions
Illinois	Consultants hired to study Illinois Power decision to scrub Baldwin (see update in Chapter 2 of this report).	Public Act 87-173 requires use of state coal at current level and receive up-front prudence and cost recovery in CWIP (preapproval). Also requires scrubbers in future.
Indiana	Commission guidelines for compliance require plans to meet or exceed CAAA, serve public interest, address state coal use, and allow reliable, efficient, economic service.	Public Law 76-1991 allows utilities to submit compliance plans to gain preapproval.
Iowa	Rulemaking Docket RMU-93-1 on Notice of Inquiry Docket NOI-91-1 and Administrative Code 199-20. The Commission will not preapprove any plan, but cost recovery through ARC in rate case.	Iowa Administrative Code 199-20 on implementation of the CAAA in 1993.
Kansas	Informal discussion of preapproval of regulatory treatment and review IRP plans.	No activity noted.
Kentucky	Opened generic Docket No. 339 on CAAA. Commission has approved consultant to review compliance plans and manage the application of monthly surcharge. Dealt with when case filed (none pending). Jurisdictional dispute over compliance at cooperative.	KRS 278-183 allows cost recovery of compliance through monthly surcharges. Geared toward quick cost recovery on scrubbers.
Louisiana	No activity noted.	Elected Section 406.

State	Public Utility Commission	Other Regulatory Actions
Maine	No activity noted.	No activity noted.
Maryland	Commission has used a surcharge mechanism for compliance costs in Potomac Electric Power case. Compliance plans have all been informally submitted.	No activity noted.
Massachusetts	Adopted the application of environmental externalities to existing and new generation. Adoption of California vehicle emissions standard is currently being challenged. Opened a generic docket on resource planning procurement in May 1993.	1987 state law restricts emissions to 1.2 pounds SO_2 per mmBtu on company and state average in 1995.
Michigan	No activity noted.	Discussions on legislation. Fossil fuel units face state emissions restriction of 1.0 pound SO_2 per mmBtu.
Minnesota	No activity noted.	State emissions cap on a systemwide basis. The CAAA will be addressed in IRP process.
Mississippi	CWIP will be ratebased and cost will appear in monthly Commission-authorized environmental cost recovery rider (ECO). ECO will operate on a projected test year and will involve Commission review and approval before and after compliance implementation effort.	No activity noted.

State	Public Utility Commission	Other Regulatory Actions
Missouri	Commission conducted survey on Title IV. Commission will not provide preapproval of compliance plans and reserves the right to hindsight reviews. Commission created new IRP process that will integrate compliance planning in May 1993.	No activity noted.
Montana	No activity noted.	Elected Section 406.
Nebraska	No activity noted.	No activity noted.
Nevada	Commission opened Docket 92-11070 seeking comments on allowance treatment and compliance issues. Department of Environmental Protection is writing CEM manual.	Elected Section 406.
New Hampshire	Commission requested comments on CAAA and FERC accounting standards on emission allowances. Flow through of costs in FAC allowed in PSCNH bankruptcy.	State law caps emissions similar to federal law, but affects all units in phase I.
New Jersey	Commission has suggested that--on a net basis--allowances cannot be purchased by utilities in the state to comply with Title IV as the state desires "real emission reductions."	No activity noted.
New Mexico	Commission mailed generic questionnaire on CAAA issues. IRP docket still open from March 1991. Formed Clean Air Task Force consisting of utilities, generators, Environmental Department, and Commission.	Elected Section 406.

State	Public Utility Commission	Other Regulatory Actions
New York	Commission collected comments from docket on trading, usage, ratemaking treatment of emission allowances.	State environmental agency may restrict allowance trading due to "deposition neutrality" law.
North Carolina	Awaiting Commission action on motion filed by staff for generic proceeding on allowance treatment.	No activity noted.
North Dakota	No activity noted.	No activity noted.
Ohio	Commission issued guidelines on allowance trading issues: utilities participate at own risk, benefits flow to ratepayers, allowance trading and cost to be reviewed in annual fuel proceedings. Commission ordered each electric utility to include in its 1992 long-term filing its proposed compliance plan.	Legislature passed S.B. 143 which allows voluntary filing of compliance plan to gain preapproval. It does not include up-front cost recovery nor does it eliminate prudence review of actual expenditures.
Oklahoma	No activity noted.	Elected Section 405. U.S. Supreme Court struck down law requiring at least 10% Oklahoma coal.
Oregon	Opened generic docket on externalities, guidelines for treatment of external environmental costs adopted in Order 93-695.	Law from H.B. 2175 established emission taxes, but attorney general ruled that state could not require emission adders but must consider the costs of emissions.

State	Public Utility Commission	Other Regulatory Actions
Pennsylvania	Allowance costs will flow through FAC. Docket opened to investigate trading, usage, and ratemaking treatment of emission allowances.	Law allows recovery of compliance costs through CWIP, encourages the use of state coal, allowance benefits dedicated to ratepayers.
Rhode Island	Commission examined NEPOOL's "Treatment of Sulfur Dioxide Allowances" report.	Elected Section 406.
South Carolina	No activity noted.	No activity noted.
South Dakota	Commission to have input into permit fee and other compliance legislation.	No activity noted.
Tennessee[2]	No activity noted.	No activity noted.
Texas	Commission published for external review and comments amendment dealing with regulatory recording and reporting requirements of allowances. Compliance plans incorporated into July 1993 statewide energy plan.	Deferred to be Clean State.
Utah	Committee of utilities and Department of Environmental Quality formed to examine solutions to Salt Lake City air problems.	Elected to be Clean State, Section 403(a). Emissions to be measured.
Vermont	No activity noted.	Elected to Section 406.
Virginia	No activity noted.	1986 tax credit available for using Virginia-mined coal, has been enhanced.

[2] Tennessee's affected units are mostly nonjurisdictional Tennessee Valley Authority units.

State	Public Utility Commission	Other Regulatory Actions
Washington	No activity noted.	Law passed on state compliance requiring the use of the best control technology available for new units and for existing units--reasonably available.
West Virginia	Commission ruled that revenue from sale of allowances will be deferred and considered in annual fuel proceedings, with proceeds going to ratepayers.	No activity noted.
Wisconsin	Docket 05-EP-6 finalized with benefits of allowance transactions accruing to ratepayers. After 1995, utilities that buy from nonutility generators may avoid depleting SO_2 allowances. These avoided costs may be reflected in purchase contacts.	Law caps emissions at 1.2 pounds SO_2 per mmBtu effective January 1993.
Wyoming	No activity noted.	Elected Section 406. Emissions to be measured. Governor has ordered Attorney General to investigate laws in IL, IN, OH, and PA to determine whether regulations there violate CAAA or interstate commerce.

Sources: Telephone interviews with state commissions' staffs in April-July 1993, conversations with Edison Electric Institute and Terra Group staffs; and Rose and Burns, *Regulatory Policy Issues and the Clean Air Act*.